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Chapter 1

Introduction and Organization of Report

1.1 Introduction

1.1.1 Major Elements in This Rate Review

The current rate proposal focuses on proposing one set of rates that will cover the two-year period 2007-2008. City Light's rate process has three major elements, each of which is discussed in a separate document. These elements are, respectively: a revenue requirement analysis, a cost of service/revenue requirement allocation analysis, and the design of customer rates and charges.

Analyses supporting the rate proposal are in three documents, one for each of the three major elements of the rate review. These documents are: the *Revenue Requirements Analysis 2007-2008 (RRA)*, the *Cost of Service and Cost Allocation Report 2007-20087 (COSACAR),* and the *Rate Design Report 2007-2008 (RDR)*. Separate from, but playing a role in a rate review is a *Budget*.

The *RRA* determines the amount of revenue that must be collected from retail customers in the Department's service area in order to cover projected costs and meet the financial guidelines prescribed for the Department by the City Council.

The *RRA* is consistent with the proposed *Budget* for the years 2007-2008. A few of the important differences between a *Budget* and an *RRA* are the following. A *Budget* refers to spending authority whereas an *RRA* determines amounts of monies needed from retail customers in a year. For example, a *Budget* shows all the capital costs to be spent in a year while an *RRA* determines how much of those costs should be ascribed to the activities of the year in question and passed on to retail customers that year. The RRA also explicitly incorporates the effects of financial policies on needed revenues.

The *COSACAR* -- this report -- details the costs of providing service to City Light customers and describes the Cost of Service Model (COSM) that is used to allocate revenue requirements to each customer class.

The *RDR* lays out the rates for each customer class that will collect revenue requirements allocated to that class.

In sum, a *Budget* determines the activities that will take place in the Department, the *RRA* determines the overall level of a rate change, the *COSACAR* determines how much revenue requirement each customer class will be allocated, and the *RDR* determines specific rate structures that will be used to collect the required revenues from each class. The rate structures will also affect the bills of the individual customers within each class.

The Cost of Service Model described in this document represents a zero-sum game. Revenue requirements not assigned to one class must be assigned to some other class(es). Revenue requirements are allocated by the COSM among classes, in the first instance, based on each class's share of the cost of providing service to all the classes. Thus, the COSM develops estimates of the cost of providing service to each class, sums the results over all classes, and computes the share of total cost for each class. Those shares for all the classes are used, then, to allocate the revenue requirements determined by the RRA document. The COSM next incorporates, after this basic allocation of revenue requirements, adjustments reflecting a number of contractual agreements with franchise cities and several policy directives.

Note that there are two types of costs referenced in the title *Cost of Service and Cost Allocation Report*. The first, Cost of Service, refers to costs that the Department or society at large sees in doing business and providing services, for example direct costs of power plus costs to society for water and air pollution in producing power. The second, Cost Allocation, refers to the revenue requirements assigned by the RRA document to be recovered from retail customers. These revenue requirements are the costs that the retail customers see. As will be explained in detail below, costs seen by the Department or society associated with serving individual classes of customers are used in a process to allocate among the individual rate classes the revenue requirements from the RRA. Though the two kinds of costs are related, they are not identical.

As mentioned at the outset, this rate proposal is for the two-year period 2007 through 2008. The analysis begins with RRA estimates of revenue requirements for each of those years. The results are added together when processed through the Cost of Service Model. Similarly, cost estimates for determining shares are estimated for each of the two years separately, but then those costs, and associated loads, are added together to determine shares to be used for purposes of allocating revenue requirements and loads to use in estimating annual average rates.

1.1.2 Most Recent and Current Formal Rate Cases

The last formal rate case was in 1999 and culminated in new base rates that went into effect December 24, 1999 with another set of somewhat higher rates to take effect March 1, 2002. That rate case introduced network rates to customers in the downtown network area as well as different rates for customers in the suburbs (excluding Tukwila which had then a franchise agreement that stipulated customers in Tukwila would pay the same rate as customers in Seattle). Subsequent to that rate case, City Light and most electric utilities on the West Coast were subjected to extraordinarily high wholesale prices for two years. And, in 2001, the Northwest suffered one of the worst water years on record thereby substantially reducing output of hydro systems and, for City Light, substantially increasing the need to buy power on the wholesale market. The City Council responded by passing ordinances that adjusted retail rates in ten separate instances. These rate changes were, essentially, either surcharges or reductions to existing rates in proportion to changes in power costs. These rate changes did not involve a full-scale formal rate review.

This *COSACAR* uses revenue requirements developed in the *RRA*. Rates are developed for the period January 1, 2007 through the end of 2008 in this rate case. The *RRA* indicates that the system average rate is expected to decline 4.8 percent in 2007 compared to the system average rate using current retail rates. Chapter 2 presents a summary of rates and rate changes for all the individual rate classes.

1.1.3 New Rates and New Policies

City Light establishes retail rates, in major part, to recover costs of providing electricity services to the various customer classes. These costs of provision change over time as the costs of equipment and operations and maintenance change. As average costs rise or fall, new rates for retail customers become appropriate. But, even if average costs do not change, it may be appropriate to change rates. This can occur because cost changes associated with providing electricity services may not be uniform among all classes. Costs for serving some classes may rise while costs for serving other classes might decline. In this latter case, there is a rationale for new rates even though the average cost has not changed.

It has been six years since rates were last formally analyzed and updates to the cost of service analysis indicate that costs did not change uniformly for all customer classes. New rates are appropriate at this time, if for no other reason than to have rates for the different classes more accurately reflect possible changes in the relative costs of providing services to the various rate classes.

Additionally, circumstances facing the utility change over time and perceptions of appropriate public policy change over time. Retail rates should reflect these changes in circumstances and changes in policy preferences.

Analyses for this rate case reflect both changes in circumstances facing the utility and changes in public policy. There have been two changes that need to be reflected in new rates.

One change deals with customers in Tukwila. The franchise agreement with Tukwila in effect as of the last formal rate case stipulated that customers in Tukwila pay the same rates as customers within Seattle. That franchise was superceded by a new agreement in 2003 similar, in general, to franchise agreements in the late 1990’s with four other cities. The new agreement provides some benefits to Tukwila and, in exchange, allows, among other things, City Light to charge higher rates to Tukwila customers for both the power and non-power portions of rates.

The other change deals with Seattle streetlights. The state Supreme Court ruled that City Light could not bill customers within Seattle for public streetlight services within the city, as was implemented in the 1999 rate case. Hence, developing rates for streetlights this time must differ from what was done in the last rate case and revert to a process more similar to the processes used in earlier rate cases.

In summary, this *COSACAR* develops revenue requirement targets and average annual rates for individual customer classes:

- that incorporate updated cost of service calculations
- that reflect the different franchises in the suburban areas

1.2 Framework of the Analysis

The basic framework used in this *COSACAR* is the same as that which has been used in cost of service and cost allocation studies since 1980. That framework continues to have the following features:

- In making its cost of service determination, City Light uses a marginal cost framework that measures the incremental cost to the Department and society resulting from an increase in the number of customers within a customer class and from an increased load on the system by class.

- Time differentiation of costs is used, corresponding to when the cost of providing energy to City Light's customers is more expensive versus less expensive.

Modifications to this basic framework, however, are made in constructing results presented in this *COSACAR* to reflect the policy initiatives indicated above and to incorporate network customers from the beginning of the analysis. The 1999 rate case introduced network customers towards the end of the analysis since adoption of network rates was a question to be determined in that case. Since network rates were adopted, the analysis here must now start with network customers as a distinct class.

A critical aspect of the *COSACAR* analysis, similar to the analysis in the last rate review, is that the retail revenue requirements are separated into functional cost categories such as energy, various distribution services, customer service, etc., rather than treated as a whole. Details of this functionalization of the revenue requirements, the results of which are used here in the *COSACAR*, are presented in the *RRA*.

The various marginal costs are separated into seven major categories, two of which are further separated into network and nonnetwork subgroups, representing energy, various distribution services and customer services. Marginal cost shares by customer class for each of these individual cost categories are used to allocate the functionalized revenue requirements and the cost shares of the total of all marginal costs are used to allocate the revenue requirement associated with the policy-determined revenue requirement assigned to provide rate relief to low-income residential customers.

1.3 Organization of the Report

There are ten chapters in the *Proposed Cost of Service and Cost Allocation Report 2007-2008*. This first chapter is introductory material. A summary of the analysis and results is presented in Chapter 2. A review of the policy framework governing the cost of service is presented in Chapter 3. The fourth chapter gives an overview of the cost of service methodology and a short statement about the marginal values of energy by costing periods used in attaching value to the electricity used by different customer classes. Chapter 5 summarizes loads in terms of the patterns of energy use that correspond to the costing periods for each of the different customer classes. These patterns of use are referred to as time-of-use estimates. Chapter 5 also presents estimates of energy losses associated with serving the loads, as well as number of meters by major customer class. Chapter 6 presents estimates of the planning values for energy and transmission cost which, together, along with the load plus loss data in the previous chapter, determine energy cost shares to allocate energy-related revenue requirements.

Details about calculating the marginal cost by customer class for the various components of distribution, and customer costs are presented in Chapters 7 and 8, respectively. Chapter 9 presents a summary of all the marginal cost shares and, then, the initial allocation of revenue requirements based on those shares. Chapter 10 presents final adjustments including those associated with the franchise contracts. The final results from Chapter 10 are summarized in Chapter 2.

Chapter 2

Summary and Conclusions

2.1 Overview

This rate case covers the two-year period January 1, 2007 through December 31, 2008. The revenue requirements to be derived from retail customers, as explained in *the 2007-08 Revenue Requirements Analysis*, have been set in order to secure several objectives. ■ Financial health for the department ■ Resources sufficient to allow stewardship of the department's physical assets and preservation of natural resources affected by those assets ■ Reliability of service by maintaining and operating the electrical system to comply with new federal electrical standards. Rates needed to cover these revenue requirements have been set with two principal objectives. ■ Stability over time and ■ Fairness such that each customer class pays a rate that reflects the true cost of service.

Based on revenue requirements for these two years, average system (retail) rate equals $56.79 per MWH in 2007 and $60.97 per MWH in 2008 (see Table 2.1). These rates are materially different from each other. Separate (and different) rates could be set for each of these two years. Such a decision would nicely tie revenue from retail customers to revenue needs of the department on an annual basis. Such a decision, though, would provide unwanted rate instability for the department's retail customers. <u>Stable rates for a two year period</u>, when at all possible, is a preferred alternative in order to provide retail rate stability for a reasonable period of time which allows improved ability to set budgets for retail customers.

Rates could be set to recover revenue requirements for either year. If rates were set to recover revenue requirements for 2007, those rates would significantly under-recover revenue requirements in 2008. Reciprocally, if rates were set to recover revenue requirements for 2008, those rates would significantly over-recover revenue requirements in 2007. Hence, <u>revenue requirements for the two years are summed and are allocated to the sum of the loads in the two-year period</u>. This process sets rates that collect over the two years an amount of revenue equal to the total needed for the two-year period. This result is equitable to both customers and the department and meets the financial policies in each year.

Rates to individual classes since the early 1980s have been determined, first, by allocating revenue requirements based on marginal cost shares (explained more fully below) then adjusting those rates by gradualism so that individual rate classes did not suffer undue rate changes compared to other classes. It has been a long-term goal of the department to eliminate the distortions associated with the gradualism adjustments.

In the last rate case in 1999, network rates, higher than rates to other customers, were introduced. Network service costs more than nonnetwork service. The higher rates to network customers in the last rate case were a start in the process of recovering the cost of providing network service. That rate case, though, did not get to the ultimate target of total cost recovery from network customers.

This rate case culminates progress towards these two policy goals. Gradualism adjustments are eliminated. Network service is now charged for full cost of service. Customer classes pay rates based on cost of service and, in the case of suburban customers, based on franchise contract terms.

2.2 Revenue Requirements

Revenue requirements cover costs to the department for all the power, labor and other items required to serve the retail customers. These revenue requirements are unbundled or functionalized, i.e., divided among cost categories. The functionalized components of the revenue requirements are then allocated among customer classes based on each class's share of costs of provision of each component. **Table 2.1** presents the derivation of revenue requirements for 2007 and 2008. The *2007-08 Revenue Requirements Analysis* gives a detailed explanation of this derivation.

Note that revenue requirements for two of the components, Wires and Related Equipment and Transformers, are further subdivided between nonnetwork and network customers. There are sufficient data available from accounting records and the Financial Planning Model from which the revenue requirements are derived to permit this further sub-division. No other components of the revenue requirements can be so sub-divided. The accounting records for network costs, used in separating the costs for these two components between nonnetwork and network areas, include costs for the downtown network, the area for which network rates apply, as well as two other, smaller, areas that receive network service. These two other areas are significantly less congested and have more overhead services than the downtown network area. The cost of service in these two smaller network areas, therefore, are not as great as cost of service in the downtown area. The downtown area comprises about 85 percent of the total load of all three network areas. Hence, network costs for rate-purposes for these two revenue requirement components are multiplied by 85 percent. Nonnetwork customers are assigned the total revenue requirement for these two components less what is assigned to network customers.

Another important note is that net wholesale revenues to be received by City Light are much greater than they have been in the past. In the past when they were essentially negligible, they were assigned to energy costs. They are now so large they distort actual energy costs by a significant amount. They have, therefore, been removed from the

Table 2.1
Functionalized Revenue Requirements, 2007

	Total excluding Net Whlsale	Direct Expenses	Revenue Offsets & Additions	Direct Expenses (Net)	Depreciation and Amortization	Capital Contributions and Grants	Interest	Admin. and General	Rev. Taxes & County Payments	Net Income	Net Wholesale Revenue	Total Revenue Req'm't
Total Energy	**492,158,175**	**313,851,741**	**(35,271,247)**	**278,580,494**	**25,588,885**	**(613,889)**	**23,819,311**	**14,011,177**	**41,083,100**	**109,689,097**	**(117,837,848)**	
Power	423,807,699	268,669,328	(30,475,966)	238,193,362	18,704,191	0	16,261,757	12,099,485	34,738,442	103,810,462	(98,590,417)	
Conservation	17,116,600	2,422,745	(300,000)	2,122,745	3,998,844	0	4,962,189	826,628	1,346,361	3,859,834	(4,084,379)	
Transmission-Long Distance	51,233,875	42,759,668	(4,495,281)	38,264,387	2,885,850	(613,889)	2,595,364	1,085,064	4,998,297	2,018,801	(15,163,052)	
Total Retail Services	**226,083,098**	**83,685,630**	**(16,988,674)**	**66,696,956**	**64,953,924**	**(29,400,232)**	**35,791,304**	**40,067,315**	**20,133,602**	**27,840,229**	**(61,078,175)**	
Total Distribution	157,635,254	46,219,277	(12,043,661)	34,175,616	52,792,791	(29,400,232)	34,307,473	25,774,334	13,299,240	26,686,033	(40,345,156)	
Transmission-In Service Area	*9,552,513*	*3,817,070*	*(410,464)*	*3,406,606*	*1,951,657*	*(313,793)*	*1,108,475*	*1,654,753*	*882,588*	862,226	(2,677,457)	
Stations	*31,407,773*	*11,505,007*	*(1,026,000)*	*10,479,007*	*5,054,748*	*(60,951)*	*3,260,545*	*7,206,009*	*2,932,204*	2,536,211	(8,895,262)	
Wires and Related Equipment	*79,160,235*	*22,369,488*	*(10,920,756)*	*11,448,732*	*34,192,925*	*(24,422,089)*	*22,182,187*	*12,216,914*	*6,287,175*	17,254,391	(19,073,049)	
non-network	*55,831,676*	*19,001,704*	*(9,427,161)*	*9,574,543*	*21,745,339*	*(15,531,476)*	*14,106,987*	*10,407,327*	*4,555,849*	10,973,106	(13,820,823)	
network	*23,328,560*	*3,367,784*	*(1,493,595)*	*1,874,188*	*12,447,586*	*(8,890,613)*	*8,075,199*	*1,809,587*	*1,731,326*	6,281,286	(5,252,226)	
Transformers	*17,576,927*	*1,333,028*	*313,559*	*1,646,587*	*8,063,549*	*(4,329,390)*	*5,658,656*	*797,853*	*1,338,092*	4,401,580	(4,059,294)	
non-network	*9,595,164*	*409,004*	*313,559*	*722,563*	*4,673,010*	*(2,508,980)*	*3,279,319*	*163,010*	*715,426*	2,550,815	(2,170,348)	
network	*7,981,763*	*924,024*		*924,024*	*3,390,540*	*(1,820,410)*	*2,379,336*	*634,843*	*622,666*	1,850,764	(1,888,947)	
Streetlights/Floodlights	*9,568,298*	*4,228,002*		*4,228,002*	*1,558,612*	*(274,010)*	*711,403*	*1,875,368*	*915,559*	553,364	(2,777,481)	
Meters	*10,369,508*	*2,966,682*		*2,966,682*	*1,971,300*	*0*	*1,386,208*	*2,023,436*	*943,622*	1,078,260	(2,862,612)	
Customer Accounts & Services	59,600,476	30,431,188	(4,833,023)	25,598,165	11,730,654	0	1,431,307	13,787,040	5,939,970	1,113,340	(18,019,753)	
Low-Income Assistance	8,847,368	7,035,165	(111,990)	6,923,175	430,479		52,525	505,942	894,392	40,856	(2,713,266)	
Total	**718,241,273**	**397,537,371**	**(52,259,921)**	**345,277,450**	**90,542,809**	**(30,014,121)**	**59,610,615**	**54,078,492**	**61,216,702**	**137,529,326**	**(178,916,023)**	**539,325,250**
Load (MWh)	**9,496,231**											
Average Cost per MWh	$75.634	$41.863	($5.503)	$36.359	$9.535	($3.161)	$6.277	$5.695	$6.446	$14.483	($18.841)	$56.794
Percent of Total Cost	100.00%	55.35%	-7.28%	48.07%	12.61%	-4.18%	8.30%	7.53%	8.52%	19.15%	-24.91%	75.09%

Functionalized Revenue Requirements, 2008

	Total excluding Net Whlsale	Direct Expenses	Revenue Offsets & Additions	Direct Expenses (Net)	Depreciation and Amortization	Capital Contributions and Grants	Interest	Admin. and General	Rev. Taxes & County Payments	Net Income	Net Wholesale Revenue	Total Revenue Req'm't
Total Energy	**470,083,424**	**301,619,779**	**(26,959,560)**	**274,660,219**	**27,177,519**	**(660,151)**	**22,745,763**	**15,286,858**	**41,546,306**	**89,326,909**	**(88,309,064)**	
Power	395,835,092	252,788,317	(22,148,765)	230,639,552	19,491,369	0	15,528,832	13,201,112	34,611,401	82,362,826	(72,703,792)	
Conservation	18,580,634	2,488,160	(300,000)	2,188,160	4,735,720	0	4,738,541	901,890	1,443,799	4,572,525	(3,248,908)	
Transmission-Long Distance	55,667,698	46,343,302	(4,510,795)	41,832,507	2,950,430	(660,151)	2,478,390	1,183,856	5,491,107	2,391,559	(12,356,364)	
Total Retail Services	**250,181,689**	**87,968,698**	**(17,379,105)**	**70,589,593**	**68,165,609**	**(21,834,397)**	**34,178,173**	**43,715,341**	**22,386,639**	**32,980,732**	**(50,375,535)**	
Total Distribution	177,854,360	48,927,460	(12,331,964)	36,595,496	55,524,726	(21,834,397)	32,761,219	28,121,020	15,072,876	31,613,421	(33,917,740)	
Transmission-In Service Area	*9,973,126*	*3,880,394*	*(419,245)*	*3,461,149*	*2,028,649*	*(324,672)*	*1,058,516*	*1,805,414*	*922,640*	1,021,431	(2,076,172)	
Stations	*33,615,499*	*12,222,637*	*(1,053,702)*	*11,168,935*	*5,318,709*	*(7,376)*	*3,113,590*	*7,862,097*	*3,155,038*	3,004,505	(7,099,624)	
Wires and Related Equipment	*93,060,116*	*23,764,796*	*(11,181,031)*	*12,583,765*	*35,978,492*	*(17,938,929)*	*21,182,425*	*13,329,233*	*7,484,837*	20,440,293	(16,842,755)	
non-network	*65,218,607*	*20,186,945*	*(9,648,251)*	*10,538,694*	*22,880,888*	*(11,408,444)*	*13,471,179*	*11,354,888*	*5,382,190*	12,999,212	(12,111,272)	
network	*27,841,510*	*3,577,851*	*(1,532,780)*	*2,045,071*	*13,097,604*	*(6,530,484)*	*7,711,246*	*1,974,345*	*2,102,647*	7,441,081	(4,731,483)	
Transformers	*19,914,630*	*1,416,177*	*322,014*	*1,738,191*	*8,484,631*	*(3,311,750)*	*5,403,617*	*870,495*	*1,515,145*	5,214,300	(3,409,455)	
non-network	*10,897,217*	*434,516*	*322,014*	*756,530*	*4,917,036*	*(1,919,234)*	*3,131,519*	*177,851*	*811,709*	3,021,805	(1,826,548)	
network	*9,017,413*	*981,660*		*981,660*	*3,567,595*	*(1,392,516)*	*2,272,099*	*692,644*	*703,436*	2,192,495	(1,582,907)	
Streetlights/Floodlights	*10,249,935*	*4,491,726*		*4,491,726*	*1,640,003*	*(251,671)*	*679,339*	*2,046,116*	*988,883*	655,539	(2,225,233)	
Meters	*11,041,054*	*3,151,731*		*3,151,731*	*2,074,242*	*0*	*1,323,731*	*2,207,665*	*1,006,333*	1,277,353	(2,264,500)	
Customer Accounts & Services	62,977,950	31,633,661	(4,932,278)	26,701,383	12,193,422	0	1,366,797	15,042,314	6,355,122	1,318,911	(14,300,614)	
Low-Income Assistance	9,349,379	7,407,577	(114,863)	7,292,714	447,461		50,157	552,006	958,641	48,400	(2,157,181)	
Total	**720,265,113**	**389,588,477**	**(44,338,665)**	**345,249,812**	**95,343,128**	**(22,494,548)**	**56,923,936**	**59,002,199**	**63,932,945**	**122,307,641**	**(138,684,599)**	**581,580,514**
Load (MWh)	**9,677,386**											
Average Cost per MWh	$74.428	$40.258	($4.582)	$35.676	$9.852	($2.324)	$5.882	$6.097	$6.606	$12.638	($14.331)	$60.097
Percent of Total Cost	100.00%	54.09%	-6.16%	47.93%	13.24%	-3.12%	7.90%	8.19%	8.88%	16.98%	-19.25%	80.75%

Table 2.2

Functionalized Revenue Requirement, Sum of 2007 & 2008

	Total excluding Net Whlsale	Direct Expenses	Revenue Offsets & Additions	Direct Expenses (Net)	Depreciation and Amortization	Capital Contributions and Grants	Interest	Admin. and General	Rev. Taxes & County Payments	Net Income	Net Wholesale Revenue	Total Revenue Req'm't
Total Energy	**962,241,599**	**615,471,520**	**(62,230,806)**	**553,240,714**	**52,766,404**	**(1,274,040)**	**46,565,073**	**29,298,035**	**82,629,406**	**199,016,006**	**(206,146,912)**	
Power	819,642,791	521,457,645	(52,624,731)	468,832,914	38,195,561	0	31,790,590	25,300,597	69,349,842	186,173,287	(171,294,209)	
Conservation	35,697,234	4,910,905	(600,000)	4,310,905	8,734,564	0	9,700,730	1,728,518	2,790,160	8,432,358	(7,333,288)	
Transmission-Long Distance	106,901,573	89,102,970	(9,006,075)	80,096,895	5,836,280	(1,274,040)	5,073,754	2,268,920	10,489,404	4,410,360	(27,519,415)	
Total Retail Services	**476,264,787**	**171,654,328**	**(34,367,780)**	**137,286,548**	**133,119,533**	**(51,234,629)**	**69,969,478**	**83,782,656**	**42,520,241**	**60,820,961**	**(111,453,710)**	
Total Distribution	335,489,615	95,146,737	(24,375,626)	70,771,111	108,317,517	(51,234,629)	67,068,692	53,895,353	28,372,116	58,299,454	(74,262,896)	
Transmission-In Service Area	*19,525,639*	*7,697,464*	*(829,710)*	*6,867,754*	*3,980,305*	*(638,465)*	*2,166,991*	*3,460,168*	*1,805,228*	1,883,657	(4,753,629)	
Stations	*65,023,271*	*23,727,644*	*(2,079,702)*	*21,647,942*	*10,373,458*	*(68,327)*	*6,374,135*	*15,068,105*	*6,087,242*	5,540,716	(15,994,886)	
Wires and Related Equipment	*172,220,352*	*46,134,284*	*(22,101,787)*	*24,032,497*	*70,171,417*	*(42,361,017)*	*43,364,612*	*25,546,147*	*13,772,012*	37,694,684	(35,915,804)	
non-network	*121,050,282*	*39,188,649*	*(19,075,412)*	*20,113,238*	*44,626,227*	*(26,939,920)*	*27,578,166*	*21,762,215*	*9,938,039*	23,972,318	(25,932,095)	
network	*51,170,070*	*6,945,634*	*(3,026,375)*	*3,919,259*	*25,545,190*	*(15,421,097)*	*15,786,446*	*3,783,932*	*3,833,973*	13,722,366	(9,983,709)	
Transformers	*37,491,557*	*2,749,205*	*635,573*	*3,384,778*	*16,548,180*	*(7,641,140)*	*11,062,273*	*1,668,348*	*2,853,237*	9,615,880	(7,468,750)	
non-network	*20,492,381*	*843,521*	*635,573*	*1,479,094*	*9,590,046*	*(4,428,214)*	*6,410,838*	*340,861*	*1,527,135*	5,572,620	(3,996,896)	
network	*16,999,177*	*1,905,684*	*0*	*1,905,684*	*6,958,135*	*(3,212,926)*	*4,651,435*	*1,327,487*	*1,326,102*	4,043,259	(3,471,854)	
Streetlights/Floodlights	*19,818,233*	*8,719,727*	*0*	*8,719,727*	*3,198,615*	*(525,681)*	*1,390,742*	*3,921,484*	*1,904,442*	1,208,902	(5,002,714)	
Meters	*21,410,562*	*6,118,413*	*0*	*6,118,413*	*4,045,541*	*0*	*2,709,939*	*4,231,101*	*1,949,955*	2,355,614	(5,127,113)	
Customer Accounts & Services	122,578,426	62,064,848	(9,765,301)	52,299,548	23,924,076	0	2,798,104	28,829,354	12,295,092	2,432,251	(32,320,367)	
Low-Income Assistance	18,196,747	14,442,743	(226,853)	14,215,889	877,939	0	102,682	1,057,948	1,853,032	89,256	(4,870,447)	
Total	**1,438,506,386**	**787,125,848**	**(96,598,586)**	**690,527,262**	**185,885,937**	**(52,508,669)**	**116,534,551**	**113,080,691**	**125,149,647**	**259,836,967**	**(317,600,622)**	**1,120,905,764**
Load (MWh)	**19,173,617**											
Average Cost per MWh	$75.025	$41.053	($5.038)	$36.014	$9.695	($2.739)	$6.078	$5.898	$6.527	$13.552	($16.564)	$58.461
Percent of Total Cost	100.00%	54.72%	-6.72%	48.00%	12.92%	-3.65%	8.10%	7.86%	8.70%	18.06%	-22.08%	77.92%

unbundling process and are allocated to customer classes after all other cost of service allocations have been made by marginal cost shares. These net wholesale revenues are in the next-to-last column on the right in the table. Total revenue requirements are in the last column on the right.

Table 2.2 presents the sum of the revenue requirements for the two years. Data from this table are used in allocating revenue requirements among customer classes.

2.3 Customer Groups and Classes

Differences in the cost of providing service distinguish one customer group from another. In general, there are economies of scale so that the unit cost of providing service to customers that consume larger quantities of electricity declines. The cost of raw power does not change significantly as consumption increases, but the unit cost associated with distribution and customer services typically declines for customers with larger consumption. Streetlights, including floodlights and traffic lights, have their own rate category because most of them do not have metered service and in many cases their rates include not only the cost of power and distribution services but also costs for the fixtures as well. The major customer groups are:

Residential
Small General Service, maximum demand < 50 kW
Medium General Service, 50 kWh <= maximum demand <= 1,000 kW
Large General Service , 1,000 kW <= maximum demand <= 10,000 kW
High Demand General Service, maximum demand >10,000 kW
Streetlights

Additionally, network customers, who are served by multiple feeders compared to one feeder for radial-system customers (the majority of customers), are more expensive to serve per unit of service. Thus, network groups are treated separately. Next, the department has franchise contracts with several suburban cities that require the department to make payments to the franchise cities and then, if the Seattle City Council approves in a rate case, may charge higher rates to customers in those areas than corresponding customers in Seattle. Four of these franchise contracts have identical in terms. One, with Tukwila, has some similarities to the others, but calls for higher payments to Tukwila from the department and permits higher rates to the department's customers within its territory. Hence, customer groups are divided between network customers and nonnetwork customers and the latter are further subdivided among Seattle, Tukwila and Other Suburbs.

Customer classes are identical to customer groups with two exceptions. Network service is not critical to residential and small customers quite the same way it is for larger customers within the network area. The cost of providing network service to residential and small customers is determined, but then those costs and loads are consolidated with the cost of service and loads for corresponding customers within Seattle.

In summary, revenue requirements and rates are constructed for the following 17 customer classes.

Seattle					
Residential	Small	Medium	Large	High Demand	Streetlights

Downtown Network	
Medium	Large

Tukwila				
Residential	Small	Medium	Large	High Demand

Other Suburbs			
Residential	Small	Medium	Large

2.4 Load and Shares of Load

Table 2.3 presents a summary of load by group and class as well as summaries for the Total nonnetwork areas and for the total service territory. This table comes from Table 5.4. There is no measurable difference in costs of service to nonnetwork customers. Thus revenue requirements are allocated, first, on the basis of customer groups in network and total nonnetwork categories. The nonnetwork revenue requirements are then allocated among Seattle, Tukwila and the Other Suburbs based on share of load. **Table 2.4** presents share of load data derived from Table 2.3. Table 2.4 comes from Table 5.5.

2.5 Marginal Cost Shares

Revenue requirements by the functional categories indicated in Tables 2.1 and 2.2 are allocated among customer groups based on cost of providing each category of service. More specifically, estimates are made of the marginal cost per unit to provide each type of functional category of service then this cost is multiplied by the number of units of that service projected to be required by each group in each forecast year. That product for a customer group estimates the total cost of providing that service to the group. The costs for all the customer groups are added and each customer group's share of the total is computed. These shares, called marginal cost shares, then, are used to allocate among the customer groups the corresponding functionalized revenue requirement.

Table 2.5 presents the marginal cost shares used to allocate the revenue requirements. Except for the two revenue requirement components mentioned above, Wires and Related Equipment and Transformers, the total cost for each component is allocated among nonnetwork and network customer classes that sum to 100 percent. The two other revenue requirement components have nonnetwork totals allocated among nonnetwork customers by shares that sum to 100 percent over just the nonnetwork classes. Similarly, the revenue requirements for network customers are allocated by shares that sum to 100 percent over just the network classes. Table 2.5 comes from Table 9.3 that summarizes

Table 2.3
Annual Summary MWH Load Data

		Total	Residential	Small	Medium	Large	High Demand	Lights	Total	Residential	Small
Service Territory											
Actual	**2005**	9,118,267	2,960,662	1,176,231	2,267,669	1,549,018	1,069,832	94,855			
Forecast	**2006**	9,324,655	3,118,338	1,180,814	2,302,983	1,492,548	1,135,057	94,915			
	2007	9,496,224	3,172,457	1,203,004	2,351,395	1,520,704	1,153,749	94,915			
	2008	9,677,381	3,239,276	1,228,235	2,399,250	1,548,101	1,167,604	94,915			
	Sum of 2007 & 2008										
		19,173,605	6,411,733	2,431,239	4,750,645	3,068,805	2,321,353	189,830			
Total Nonnetwork (Excludes Network Residential & Small)									**Includes Ntwk Res & Small**		
Actual	**2005**	7,793,960	2,892,983	1,022,558	1,780,111	933,621	1,069,832	94,855	8,015,312	2,960,662	1,176,231
Forecast	**2006**	7,991,428	3,044,089	1,027,766	1,808,338	881,263	1,135,057	94,915	8,218,725	3,118,338	1,180,814
	2007	8,137,774	3,096,874	1,047,363	1,846,776	898,097	1,153,749	94,915	8,368,998	3,172,457	1,203,004
	2008	8,290,732	3,162,046	1,069,385	1,884,141	912,641	1,167,604	94,915	8,526,812	3,239,276	1,228,235
	Sum of 2007 & 2008										
		16,428,506	6,258,920	2,116,748	3,730,917	1,810,738	2,321,353	189,830	16,895,810	6,411,733	2,431,239
Downtown Network (Includes Network Residential & Small)									**Excludes Ntwk Res & Small**		
Actual	**2005**	1,324,307	67,679	153,673	487,558	615,397			1,102,955		
Forecast	**2006**	1,333,227	74,249	153,048	494,645	611,285			1,105,930		
	2007	1,358,450	75,583	155,641	504,619	622,607			1,127,226		
	2008	1,386,649	77,230	158,850	515,109	635,460			1,150,569		
	Sum of 2007 & 2008										
		2,745,099	152,813	314,491	1,019,728	1,258,067			2,277,795		
City of Seattle Nonnetwork (Excludes Network Residential & Small)									**Includes Ntwk Res & Small**		
Actual	**2005**	6,340,580	2,234,954	851,451	1,494,932	714,568	949,820	94,855	6,561,932	2,302,633	1,005,124
Forecast	**2006**	6,507,978	2,346,715	858,026	1,526,347	749,252	932,723	94,915	6,735,275	2,420,964	1,011,074
	2007	6,626,235	2,387,505	874,307	1,558,064	763,414	948,030	94,915	6,857,459	2,463,088	1,029,948
	2008	6,751,812	2,437,868	892,648	1,589,438	776,223	960,720	94,915	6,987,892	2,515,098	1,051,498
	Sum of 2007 & 2008										
		13,378,047	4,825,373	1,766,955	3,147,502	1,539,637	1,908,750	189,830	13,845,351	4,978,186	2,081,446
Tukwila											
Actual	**2005**	488,722	52,060	31,249	89,728	195,673	120,012				
Forecast	**2006**	488,775	56,723	31,028	89,041	109,649	202,334				
	2007	497,652	57,680	31,640	90,993	111,620	205,719				
	2008	503,564	58,863	32,323	92,634	112,860	206,884				
	Sum of 2007 & 2008										
		1,001,216	116,543	63,963	183,627	224,480	412,603				
Other Suburbs											
Actual	**2005**	964,658	605,969	139,858	195,451	23,380					
Forecast	**2006**	994,675	640,651	138,712	192,950	22,362					
	2007	1,013,887	651,689	141,416	197,719	23,063					
	2008	1,035,356	665,315	144,414	202,069	23,558					
	Sum of 2007 & 2008										
		2,049,243	1,317,004	285,830	399,788	46,621					

Table 2.4
Annual Share of Load

		Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory								
Actual	**2005**	100.000%	32.470%	12.900%	24.870%	16.988%	11.733%	1.040%
Forecast	**2006**	100.000%	33.442%	12.663%	24.698%	16.006%	12.173%	1.018%
	2007	100.000%	33.408%	12.668%	24.761%	16.014%	12.150%	1.000%
	2008	100.000%	33.473%	12.692%	24.792%	15.997%	12.065%	0.981%
	2007+08	100.000%	33.440%	12.680%	24.777%	16.005%	12.107%	0.990%
Total Nonnetwork (Excludes Network Residential & Small)								
Actual	**2005**	100.000%	37.118%	13.120%	22.840%	11.979%	13.726%	1.217%
Forecast	**2006**	100.000%	38.092%	12.861%	22.628%	11.028%	14.203%	1.188%
	2007	100.000%	38.056%	12.870%	22.694%	11.036%	14.178%	1.166%
	2008	100.000%	38.140%	12.899%	22.726%	11.008%	14.083%	1.145%
	2007+08	100.000%	38.098%	12.885%	22.710%	11.022%	14.130%	1.155%
Downtown Network (Includes Network Residential & Small)								
Actual	**2005**	100.000%	5.111%	11.604%	36.816%	46.469%		
Forecast	**2006**	100.000%	5.569%	11.480%	37.101%	45.850%		
	2007	100.000%	5.564%	11.457%	37.147%	45.832%		
	2008	100.000%	5.570%	11.456%	37.148%	45.827%		
	2007+08	100.000%	5.567%	11.456%	37.147%	45.830%		
City of Seattle Nonnetwork (Excludes Network Residential & Small) as Percent of Total Nonnetwork by Class								
Actual	**2005**	81.352%	77.254%	83.267%	83.980%	76.537%	88.782%	100.000%
Forecast	**2006**	81.437%	77.091%	83.485%	84.406%	85.020%	82.174%	100.000%
	2007	81.426%	77.094%	83.477%	84.367%	85.004%	82.170%	100.000%
	2008	81.438%	77.098%	83.473%	84.359%	85.052%	82.281%	100.000%
	2007+08	81.432%	77.096%	83.475%	84.363%	85.028%	82.226%	100.000%
Tukwila as Percent of Total Nonnetwork by Class								
Actual	**2005**	6.271%	1.800%	3.056%	5.041%	20.959%	11.218%	
Forecast	**2006**	6.116%	1.863%	3.019%	4.924%	12.442%	17.826%	
	2007	6.115%	1.863%	3.021%	4.927%	12.429%	17.830%	
	2008	6.074%	1.862%	3.023%	4.917%	12.366%	17.719%	
	2007+08	6.094%	1.862%	3.022%	4.922%	12.397%	17.774%	
Other Suburbs as Percent of Total Nonnetwork by Class								
Actual	**2005**	12.377%	20.946%	13.677%	10.980%	2.504%		
Forecast	**2006**	12.447%	21.046%	13.496%	10.670%	2.537%		
	2007	12.459%	21.043%	13.502%	10.706%	2.568%		
	2008	12.488%	21.041%	13.504%	10.725%	2.581%		
	2007+08	12.474%	21.042%	13.503%	10.716%	2.575%		
Total Nonnetwork (Excludes Network Residential & Small) as Percent of Total Service Territory								
Actual	**2005**	85.476%	31.727%	11.214%	19.522%	10.239%	11.733%	1.040%
Forecast	**2006**	85.702%	32.646%	11.022%	19.393%	9.451%	12.173%	1.018%
	2007	85.695%	32.612%	11.029%	19.447%	9.457%	12.150%	1.000%
	2008	85.671%	32.675%	11.050%	19.470%	9.431%	12.065%	0.981%
	2007+08	85.683%	32.643%	11.040%	19.459%	9.444%	12.107%	0.990%
Downtown Network (Includes Network Residential & Small) as Percent of Total Service Territory								
Actual	**2005**	14.524%	0.742%	1.685%	5.347%	6.749%		
Forecast	**2006**	14.298%	0.796%	1.641%	5.305%	6.556%		
	2007	14.305%	0.796%	1.639%	5.314%	6.556%		
	2008	14.329%	0.798%	1.641%	5.323%	6.566%		
	2007+08	14.317%	0.797%	1.640%	5.318%	6.561%		

Table 2.5
Summary of Marginal Cost Shares by Functional Category, 2007 + 2008

	Total Nonnetwork (EXcludes Network Residential & Small)							Source
	Total	Residential	Small	Medium	Large	High Demand	Lights	
Energy								
Production	85.716%	32.907%	11.139%	19.440%	9.370%	11.904%	0.956%	Table 6.7
Purchased Power	85.716%	32.907%	11.139%	19.440%	9.370%	11.904%	0.956%	Table 6.7
Transmission - Long Distance	85.716%	32.907%	11.139%	19.440%	9.370%	11.904%	0.956%	Table 6.7
Conservation	85.716%	32.907%	11.139%	19.440%	9.370%	11.904%	0.956%	Table 6.7
Retail Service								
Total Distribution								
- Transmission - In Service Area	85.917%	37.866%	11.008%	19.000%	8.642%	8.665%	0.736%	Table 7.3
- Stations	83.852%	36.956%	10.744%	18.543%	8.434%	8.457%	0.719%	Table 7.5
- Wires & Related Equipment	100.000%	45.631%	12.755%	21.320%	9.745%	9.727%	0.431%	Table 7.11
- Transformers	100.000%	37.581%	12.855%	31.030%	9.961%	7.735%	0.838%	Table 7.22
- Meters, (except Meter Reading)	90.978%	63.407%	20.312%	6.583%	0.437%	0.239%	0.000%	Table 7.12
- Streetlights/Floodlights							100.000%	Sect. 7.1
Customer Costs	94.641%	81.860%	7.713%	1.389%	2.667%	1.010%	0.000%	Table 8.28
Low-Income Assistance	83.229%	34.376%	10.628%	17.967%	8.668%	10.729%	0.851%	Table 9.2
Total								

	Downtown Network					Source
	Total	Residential	Small	Medium	Large	
Energy						
Production	14.284%	0.799%	1.653%	5.292%	6.539%	Table 6.7
Purchased Power	14.284%	0.799%	1.653%	5.292%	6.539%	Table 6.7
Transmission - Long Distance	14.284%	0.799%	1.653%	5.292%	6.539%	Table 6.7
Conservation	14.284%	0.799%	1.653%	5.292%	6.539%	Table 6.7
Retail Service						
Total Distribution						
- Transmission - In Service Area	14.083%	0.898%	1.647%	4.994%	6.544%	Table 7.3
- Stations	16.148%	1.030%	1.888%	5.726%	7.503%	Table 7.5
- Wires & Related Equipment	100.000%	6.464%	11.681%	35.320%	46.536%	Table 7.11
- Transformers	100.000%	7.530%	15.498%	50.250%	26.722%	Table 7.22
- Meters, (except Meter Reading)	9.022%	5.754%	2.131%	0.913%	0.224%	Table 7.12
- Streetlights/Floodlights						Sect. 7.1
Customer Costs	5.359%	3.895%	0.764%	0.215%	0.485%	Table 8.28
Low-Income Assistance	16.771%	1.162%	1.993%	6.200%	7.416%	Table 9.2
Total						

the development of the marginal cost shares. Sources for the shares are indicated in the table.

2.6 Initial Allocation of Revenue Requirements

Table 2.6 on the next page presents the initial allocation of functionalized revenue requirements by marginal cost shares. This table comes from Table 9.4. **Table 2.7** following Table 2.6 presents the subdivision of the nonnetwork revenue requirements among Seattle, Tukwila and Other Suburbs. This table comes from Table 9.5 and is derived from data in the previous two tables. Tables 2.6 and 2.7 indicate the share for each customer group of all revenue requirements allocated by marginal costs. These shares are used to allocate the credit of net wholesale revenues among groups.

2.7 Adjustments for Franchise Contracts

Section 10.3 in Chapter 10 presents the development of the suburban franchise adjustments. Tukwila receives payments based on the revenue from customers in Tukwila for both power and distribution services. The Tukwila contract permits, if the Seattle City Council approves in a rate case, to charge higher rates for those services to customers in Tukwila. The other suburbs receive payments, at this time, on revenue only for power and, if the Seattle City Council approves in a rate case, higher rates for the power portion of rates may be charged to these suburbs. **Table 2.8** summarizes results presented in Table 10.3. This table presents the incremental revenue to be paid by customers in Tukwila and the Other Suburbs compared to what they would have paid in absence of the franchise contracts. The incremental revenue is recovered over the two-year period 2007-08 and is credited to Seattle residential customers.

Table 2.8
Incremental Charges per Franchise Contracts, Total for 2007 + 2008

Tukwila Energy Adjustment	**3,990,381**
Tukwila Non-Energy Adjustment	**956,743**
Tukwila, Total Adjustment	**4,947,124**
Other Suburbs Energy Adjustment	**8,277,423**
Total, All Franchise Adjustments	**13,224,547**

Table 2.6
Initial Allocation of Functionalized Revenue Requirements, 2007 + 2008

	Total Service Territory						
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	**$ 962,241,599**	**324,336,512**	**123,085,718**	**237,989,447**	**153,086,520**	**114,548,903**	**9,194,499**
Production	$ 154,094,483	51,939,624	19,711,089	38,111,905	24,515,453	18,343,994	1,472,418
Purchased Power	$ 665,548,308	224,332,036	85,134,016	164,608,840	105,884,504	79,229,404	6,359,508
Transmission - Long Distance	$ 35,697,234	12,032,234	4,566,233	8,828,931	5,679,203	4,249,535	341,097
Conservation	$ 106,901,573	36,032,617	13,674,380	26,439,770	17,007,361	12,725,970	1,021,476
Retail Service	**$ 476,264,787**	**229,958,670**	**54,878,577**	**85,652,235**	**59,201,025**	**24,736,611**	**21,837,670**
Total Distribution	**$ 335,489,615**	**118,374,362**	**42,190,699**	**79,287,625**	**52,410,367**	**21,545,680**	**21,680,882**
- Transmission - In Service Area	$ 19,525,639	7,568,923	2,471,039	4,685,039	2,965,018	1,691,848	143,772
- Stations	$ 65,023,271	24,699,643	8,213,909	15,781,054	10,362,668	5,498,722	467,276
- Wires & Related Equipment	$ 172,220,352	61,550,269	21,499,269	42,805,829	32,784,762	12,521,606	1,058,618
- Transformers	$ 37,491,557	9,747,678	5,201,475	14,410,871	6,156,225	1,782,326	192,983
- Meters, (except Meter Reading)	$ 21,410,562	14,807,850	4,805,007	1,604,832	141,696	51,178	-
- Streetlights/Floodlights	$ 19,818,233	-	-	-	-	-	19,818,233
Customer Costs	***$ 122,578,426***	**105,117,409**	**10,391,388**	**1,967,086**	**3,863,895**	**1,238,649**	**-**
Low-Income Assistance	**$ 18,196,747**	**6,466,899**	**2,296,490**	**4,397,524**	**2,926,763**	**1,952,282**	**156,788**
Total	**$ 1,438,506,386**	**554,295,181**	**177,964,295**	**323,641,681**	**212,287,545**	**139,285,514**	**31,032,169**
Percent of Total Service Territory	**100.000%**	**38.533%**	**12.371%**	**22.498%**	**14.757%**	**9.683%**	**2.157%**

	Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)						
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	**824,798,613**	**316,643,428**	**107,183,409**	**187,063,161**	**90,165,213**	**114,548,903**	**9,194,499**
Production	132,084,204	50,707,645	17,164,475	29,956,511	14,439,162	18,343,994	1,472,418
Purchased Power	570,483,881	219,011,003	74,134,954	129,384,939	62,364,073	79,229,404	6,359,508
Transmission - Long Distance	30,598,375	11,746,836	3,976,290	6,939,668	3,344,949	4,249,535	341,097
Conservation	91,632,153	35,177,943	11,907,690	20,782,043	10,017,030	12,725,970	1,021,476
Retail Service	**393,518,532**	**218,995,744**	**44,254,226**	**56,743,087**	**26,951,194**	**24,736,611**	**21,837,670**
Total Distribution	**262,364,334**	**112,397,559**	**32,865,355**	**51,770,676**	**22,104,183**	**21,545,680**	**21,680,882**
- Transmission - In Service Area	16,775,772	7,393,492	2,149,464	3,709,879	1,687,317	1,691,848	143,772
- Stations	54,523,396	24,029,792	6,986,031	12,057,579	5,483,995	5,498,722	467,276
- Wires & Related Equipment	128,725,793	58,738,891	16,418,850	27,443,733	12,544,095	12,521,606	1,058,618
- Transformers	23,042,257	8,659,586	2,962,186	7,150,035	2,295,140	1,782,326	192,983
- Meters, (except Meter Reading)	19,478,883	13,575,797	4,348,824	1,409,449	93,636	51,178	-
- Streetlights/Floodlights	19,818,233	-	-	-	-	-	19,818,233
Customer Costs	**116,009,218**	**100,342,789**	**9,454,981**	**1,703,084**	**3,269,716**	**1,238,649**	**0**
Low-Income Assistance	**15,144,980**	**6,255,395**	**1,933,891**	**3,269,327**	**1,577,296**	**1,952,282**	**156,788**
Total	**1,218,317,146**	**535,639,172**	**151,437,636**	**243,806,247**	**117,116,408**	**139,285,514**	**31,032,169**
Percent of Total Service Territory	**84.693%**	**37.236%**	**10.527%**	**16.949%**	**8.142%**	**9.683%**	**2.157%**

	Downtown Network				
	Total	**Residential**	**Small**	**Medium**	**Large**
Energy	**137,442,986**	**7,693,084**	**15,902,309**	**50,926,286**	**62,921,307**
Production	22,010,279	1,231,979	2,546,614	8,155,394	10,076,291
Purchased Power	95,064,427	5,321,033	10,999,062	35,223,902	43,520,431
Transmission - Long Distance	5,098,859	285,398	589,944	1,889,263	2,334,254
Conservation	15,269,420	854,674	1,766,689	5,657,727	6,990,330
Retail Service	**82,746,255**	**10,962,926**	**10,624,351**	**28,909,148**	**32,249,830**
Total Distribution	**73,125,281**	**5,976,803**	**9,325,344**	**27,516,949**	**30,306,184**
- Transmission - In Service Area	2,749,867	175,431	321,575	975,160	1,277,701
- Stations	10,499,876	669,850	1,227,878	3,723,474	4,878,673
- Wires & Related Equipment	43,494,559	2,811,377	5,080,419	15,362,096	20,240,667
- Transformers	14,449,300	1,088,092	2,239,288	7,260,836	3,861,084
- Meters, (except Meter Reading)	1,931,679	1,232,053	456,183	195,383	48,060
- Streetlights/Floodlights	-	-	-	-	-
Customer Costs	**6,569,208**	**4,774,619**	**936,407**	**264,002**	**594,179**
Low-Income Assistance	**3,051,766**	**211,503**	**362,599**	**1,128,197**	**1,349,467**
Total	**220,189,240**	**18,656,010**	**26,526,660**	**79,835,434**	**95,171,137**
Percent of Total Service Territory	**15.307%**	**1.297%**	**1.844%**	**5.550%**	**6.616%**

Table 2.7
Initial Allocation of 2007 + 2008 Nonnetwork Revenue Requirements among Seattle, Tukwila and Other Suburbs

	Seattle Nonnetwork						
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	**671,451,074**	**244,119,217**	**89,471,331**	**157,811,517**	**76,665,812**	**94,188,699**	**9,194,499**
Production	107,526,952	39,093,534	14,328,042	25,272,119	12,277,352	15,083,487	1,472,418
Purchased Power	464,418,839	168,848,584	61,884,139	109,152,617	53,027,017	65,146,975	6,359,508
Transmission - Long Distance	24,909,489	9,056,334	3,319,207	5,854,491	2,844,148	3,494,212	341,097
Conservation	74,595,794	27,120,765	9,939,942	17,532,291	8,517,295	10,464,025	1,021,476
Retail Service	**318,741,659**	**168,836,820**	**36,941,207**	**47,869,995**	**22,916,102**	**20,339,864**	**21,837,670**
Total Distribution	**215,955,192**	**86,653,951**	**27,434,349**	**43,675,135**	**18,794,777**	**17,716,097**	**21,680,882**
- Transmission - In Service Area	13,593,701	5,700,082	1,794,264	3,129,754	1,434,694	1,391,135	143,772
- Stations	44,181,261	18,525,993	5,831,588	10,172,099	4,662,939	4,521,366	467,276
- Wires & Related Equipment	104,163,816	45,285,298	13,705,632	23,152,272	10,666,011	10,295,985	1,058,618
- Transformers	18,790,865	6,676,189	2,472,684	6,031,962	1,951,515	1,465,531	192,983
- Meters, (except Meter Reading)	15,407,315	10,466,388	3,630,180	1,189,049	79,617	42,081	-
- Streetlights/Floodlights	19,818,233	-	-	-	-	-	19,818,233
Customer Costs	**90,488,191**	**77,360,213**	**7,892,543**	**1,436,767**	**2,780,179**	**1,018,488**	**-**
Low-Income Assistance	**12,298,276**	**4,822,656**	**1,614,315**	**2,758,092**	**1,341,146**	**1,605,279**	**156,788**
Total	**990,192,733**	**412,956,037**	**126,412,538**	**205,681,512**	**99,581,913**	**114,528,563**	**31,032,169**
Percent of Total Service Territory	**68.835%**	**28.707%**	**8.788%**	**14.298%**	**6.923%**	**7.962%**	**2.157%**

	Tukwila					
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Energy	**49,879,757**	**5,895,997**	**3,238,823**	**9,206,811**	**11,177,921**	**20,360,204**
Production	7,987,802	944,192	518,669	1,474,389	1,790,045	3,260,507
Purchased Power	34,500,055	4,078,052	2,240,179	6,368,024	7,731,371	14,082,429
Transmission - Long Distance	1,850,439	218,730	120,154	341,554	414,678	755,323
Conservation	5,541,461	655,024	359,822	1,022,843	1,241,827	2,261,945
Retail Service	**15,945,713**	**4,077,768**	**1,337,256**	**2,792,762**	**3,341,181**	**4,396,746**
Total Distribution	**12,203,892**	**2,092,877**	**993,111**	**2,548,031**	**2,740,290**	**3,829,582**
- Transmission - In Service Area	895,105	137,669	64,952	182,592	209,179	300,713
- Stations	2,909,205	447,442	211,101	593,446	679,859	977,356
- Wires & Related Equipment	6,721,322	1,093,736	496,138	1,350,716	1,555,111	2,225,621
- Transformers	1,203,989	161,244	89,510	351,908	284,532	316,795
- Meters, (except Meter Reading)	474,271	252,785	131,411	69,370	11,608	9,096
- Streetlights/Floodlights	-	-	-	-	-	-
Customer Costs	**2,863,454**	**1,868,413**	**285,707**	**83,822**	**405,352**	**220,160**
Low-Income Assistance	**878,367**	**116,477**	**58,438**	**160,909**	**195,540**	**347,003**
Total	**65,825,469**	**9,973,765**	**4,576,079**	**11,999,573**	**14,519,103**	**24,756,950**
Percent of Total Service Territory	**4.576%**	**0.693%**	**0.318%**	**0.834%**	**1.009%**	**1.721%**

	Other Suburbs				
	Total	**Residential**	**Small**	**Medium**	**Large**
Energy	**103,467,782**	**66,628,214**	**14,473,255**	**20,044,833**	**2,321,480**
Production	16,569,450	10,669,919	2,317,764	3,210,003	371,765
Purchased Power	71,564,987	46,084,367	10,010,636	13,864,298	1,605,685
Transmission - Long Distance	3,838,447	2,471,773	536,929	743,623	86,122
Conservation	11,494,898	7,402,154	1,607,926	2,226,909	257,908
Retail Service	**58,831,161**	**46,081,156**	**5,975,764**	**6,080,330**	**693,911**
Total Distribution	**34,205,250**	**23,650,731**	**4,437,894**	**5,547,509**	**569,116**
- Transmission - In Service Area	2,286,966	1,555,741	290,248	397,534	43,443
- Stations	7,432,930	5,056,357	943,342	1,292,035	141,196
- Wires & Related Equipment	17,840,654	12,359,857	2,217,080	2,940,745	322,972
- Transformers	3,047,403	1,822,153	399,992	766,165	59,093
- Meters, (except Meter Reading)	3,597,298	2,856,624	587,233	151,030	2,411
- Streetlights/Floodlights	-	-	-	-	-
Customer Costs	**22,657,573**	**21,114,163**	**1,276,731**	**182,495**	**84,185**
Low-Income Assistance	**1,968,337**	**1,316,262**	**261,138**	**350,326**	**40,611**
Total	**162,298,943**	**112,709,370**	**20,449,019**	**26,125,162**	**3,015,392**
Percent of Total Service Territory	**11.282%**	**7.835%**	**1.422%**	**1.816%**	**0.210%**

2.8 Allocation of Net Wholesale Revenue

Table 2.9 presents the allocation of net wholesale revenue among customer groups. This table comes from Table 10.4. The net wholesale revenue is a credit for each group thereby decreasing the revenue requirements each must pay.

Table 2.9
Allocation of Net Wholesale Revenue

	Service Territory						
	Total	Residential	Small	Medium	Large	High Demand	Lights
Initial Allocated Rev Reqmnts	1,438,506,386	554,295,181	177,964,295	323,641,681	212,287,545	139,285,514	31,032,169
Share of Allocated Rev Reqmnts	100.000%	38.533%	12.371%	22.498%	14.757%	9.683%	2.157%
Net Wholesale Power Credits	(317,600,622)	(122,380,058)	(39,291,846)	(71,455,226)	(46,869,904)	(30,752,151)	(6,851,437)
Net Revenue Requirements	1,120,905,764	431,915,124	138,672,450	252,186,455	165,417,641	108,533,363	24,180,732

	Total Nonnetwork						
	Total	Residential	Small	Medium	Large	High Demand	Lights
Initial Allocated Rev Reqmnts	1,218,317,146	535,639,172	151,437,636	243,806,247	117,116,408	139,285,514	31,032,169
Share of Allocated Rev Reqmnts	84.693%	37.236%	10.527%	16.949%	8.142%	9.683%	2.157%
Net Wholesale Power Credits	(268,986,142)	(118,261,091)	(33,435,157)	(53,828,761)	(25,857,545)	(30,752,151)	(6,851,437)
Net Revenue Requirements	949,331,003	417,378,081	118,002,478	189,977,487	91,258,863	108,533,363	24,180,732

	Seattle Nonnetwork						
	Total	Residential	Small	Medium	Large	High Demand	Lights
Initial Allocated Rev Reqmnts	990,192,733	412,956,037	126,412,538	205,681,512	99,581,913	114,528,563	31,032,169
Share of Allocated Rev Reqmnts	68.835%	28.707%	8.788%	14.298%	6.923%	7.962%	2.157%
Net Wholesale Power Credits	(218,619,695)	(91,174,496)	(27,909,991)	(45,411,391)	(21,986,192)	(25,286,188)	(6,851,437)
Net Revenue Requirements	771,573,038	321,781,541	98,502,547	160,270,121	77,595,721	89,242,375	24,180,732

	Tukwila					
	Total	Residential	Small	Medium	Large	High Demand
Initial Allocated Rev Reqmnts	65,825,469	9,973,765	4,576,079	11,999,573	14,519,103	24,756,950
Share of Allocated Rev Reqmnts	4.576%	0.693%	0.318%	0.834%	1.009%	1.721%
Net Wholesale Power Credits	(14,533,276)	(2,202,058)	(1,010,330)	(2,649,326)	(3,205,600)	(5,465,963)
Net Revenue Requirements	51,292,194	7,771,707	3,565,749	9,350,247	11,313,503	19,290,987

	Other Suburbs				
	Total	Residential	Small	Medium	Large
Initial Allocated Rev Reqmnts	162,298,943	112,709,370	20,449,019	26,125,162	3,015,392
Share of Allocated Rev Reqmnts	11.282%	7.835%	1.422%	1.816%	0.210%
Net Wholesale Power Credits	(35,833,171)	(24,884,537)	(4,514,836)	(5,768,044)	(665,753)
Net Revenue Requirements	126,465,772	87,824,833	15,934,182	20,357,119	2,349,638

	Network				
	Total	Residential	Small	Medium	Large
Initial Allocated Rev Reqmnts	220,189,240	18,656,010	26,526,660	79,835,434	95,171,137
Share of Allocated Rev Reqmnts	15.307%	1.297%	1.844%	5.550%	6.616%
Net Wholesale Power Credits	(48,614,480)	(4,118,967)	(5,856,688)	(17,626,466)	(21,012,359)
Net Revenue Requirements	171,574,761	14,537,043	20,669,971	62,208,968	74,158,778

2.9 Consolidation of Seattle Residential and Small Groups

Table 2.10 presents the consolidation of the residential and small customer groups in Seattle and the network area into the residential and small rate classes for Seattle. Additionally, this table shows the franchise adjustment credited to Seattle residential customers. This table comes from Table 10.5 and also shows the sources of data that are consolidated.

Table 2.10
Consolidation of Seattle Residential and Small Classes
And Crediting Seattle Residential with Revenue from Franchise Adjustments

	Seattle			Network		
	Residential	**Small**	source	**Residential**	**Small**	source
Net Rev Reqmnt	321,781,541	98,502,547	Table 10.4	14,537,043	20,669,971	Table 10.4

	Seattle + Network		
	Residential	**Small**	source
Net Rev Reqmnt	336,318,584	119,172,518	
Franchise Adjustment	(13,224,546)		Table 10.3
Adjusted Rev. Reqmnt	323,094,038	119,172,518	

2.10 Summary of Final Results

Table 2.11 presents a summary of the main results. This table presents the allocation of those portions of the two-year revenue requirements that are allocated by marginal cost shares and the share of that total associated with each class after consolidation of groups has occurred. Then it presents the allocation of wholesale net revenue by the previous shares.[1] The total revenue requirement for the two-year period for each class is then derived. Total load for the two-year period is shown and the average rate per MWH for the two-year period is derived. This rate is compared to the rate without a rate change, i.e., what the average rate for each class would be if current rates were used with the loads in the two-year period. Finally, the percentage change in rates by class is presented.

It is important when comparing percentage rate changes among customer classes to understand that this rate case has NOT used a gradualism tool as in the past. Gradualism is a policy tool that was used for the past twenty years. It was a tool used after revenue requirements had been allocated by marginal cost shares. The gradualism tool had been used when any class had a rate change, particularly an increase, that was significantly higher than the system average rate increase. Revenue requirements were reduced for that class and the reduction was distributed among other classes. The last rate case also had a rate-change floor as a part of the gradualism process in order to mitigate to some extent disparity in rate changes among customer classes. It has been a long-standing goal of the rate-making process to eliminate the use of the gradualism tool. It distorts rates from what cost-of-service indicates and gives incorrect price signals to the various classes about the true marginal cost of providing electrical service.

This rate case, finally, arrives at this goal by eliminating the use of gradualism. And, in so doing, it is important to understand that the rate without a rate change that is used as the base for purposes of computation is distorted by past uses of gradualism. **Table 2.12** (which comes from Table 10.2) illustrates the rate changes from the last (1999) rate case associated with marginal cost principles compared to the rates set by the gradualism policy put into effect at that time. The rates implied by the data in Table 2.12 have been amended ten times in the past several years and are embedded in the rates in Table 2.12, but all the amendments were equal changes to

[1] Thus net wholesale revenue is allocated, in a sense, by marginal cost shares. The allocation occurs after cumulating the allocation effects of all the other marginal cost shares.

Table 2.11
Summary Results

	Total Service Territory						
	Total	Residential	Small	Medium	Large	High Demand	Lights
Cost Share Rev.Reqmnts	1,438,506,386	554,295,181	177,964,295	323,641,681	212,287,545	139,285,514	31,032,169
Share of Cost Shr Rev Req	100.000%	38.533%	12.371%	22.498%	14.757%	9.683%	2.157%
Wholesale Net Revenue	-317,600,622	-122,380,058	-39,291,846	-71,455,226	-46,869,904	-30,752,151	-6,851,437
Other Adjustments	0	-7,177,943	1,497,202	2,507,697	1,280,423	1,892,621	0
Tot Revenue Requirement	**1,120,905,764**	**424,737,181**	**140,169,651**	**254,694,152**	**166,698,064**	**110,425,984**	**24,180,732**
Load, MWH	**19,173,605**	**6,411,733**	**2,431,239**	**4,750,645**	**3,068,805**	**2,321,353**	**189,830**
Average Rate	**58.461**	**66.244**	**57.654**	**53.613**	**54.320**	**47.570**	**127.381**
Rate without Change	61.389	67.235	58.808	60.675	57.472	53.533	75.264
Pct Chg in Rate	**-4.77%**	**-1.47%**	**-1.96%**	**-11.64%**	**-5.48%**	**-11.14%**	**69.25%**

	Total Nonnetwork (Includes Network Residential & Small)						
	Total	Residential	Small	Medium	Large	High Demand	Lights
Cost Share Rev.Reqmnts	1,263,499,815	554,295,181	177,964,295	243,806,247	117,116,408	139,285,514	31,032,169
Share of Cost Shr Rev Req	87.834%	38.533%	12.371%	16.949%	8.142%	9.683%	2.157%
Wholesale Net Revenue	-278,961,797	-122,380,058	-39,291,846	-53,828,761	-25,857,545	-30,752,151	-6,851,437
Other Adjustments	0	-7,177,943	1,497,202	2,507,697	1,280,423	1,892,621	0
Tot Revenue Requirement	**984,538,017**	**424,737,181**	**140,169,651**	**192,485,184**	**92,539,286**	**110,425,984**	**24,180,732**
Load, MWH	**16,895,810**	**6,411,733**	**2,431,239**	**3,730,917**	**1,810,738**	**2,321,353**	**189,830**
Average Rate	**58.271**	**66.244**	**57.654**	**51.592**	**51.106**	**47.570**	**127.381**
Rate without Change	61.252	67.235	58.808	59.386	55.698	53.533	75.264
Pct Chg in Rate	**-4.87%**	**-1.47%**	**-1.96%**	**-13.12%**	**-8.24%**	**-11.14%**	**69.25%**

	Network (Excludes Residential and Small)				
	Total	Residential	Small	Medium	Large
Cost Share Rev.Reqmnts	175,006,571			79,835,434	95,171,137
Share of Cost Shr Rev Req	12.166%			5.550%	6.616%
Wholesale Net Revenue	-38,638,825			-17,626,466	-21,012,359
Other Adjustments	0			0	0
Tot Revenue Requirement	**136,367,747**			**62,208,968**	**74,158,778**
Load, MWH	**2,277,795**			**1,019,728**	**1,258,067**
Average Rate	**59.868**			**61.005**	**58.947**
Rate without Change	62.210			65.392	60.026
Pct Chg in Rate	**-3.76%**			**-6.71%**	**-1.80%**

	Seattle Nonnetwork (Includes Network Res & Small)						
	Total	Residential	Small	Medium	Large	High Demand	Lights
Cost Share Rev.Reqmnts	1,035,375,403	431,612,046	152,939,198	205,681,512	99,581,913	114,528,563	31,032,169
Share of Cost Shr Rev Req	71.976%	30.004%	10.632%	14.298%	6.923%	7.962%	2.157%
Wholesale Net Revenue	-228,595,351	-95,293,463	-33,766,680	-45,411,391	-21,986,192	-25,286,188	-6,851,437
Other Adjustments	-13,224,546	-13,224,546	0	0	0	0	0
Tot Revenue Requirement	**793,555,506**	**323,094,038**	**119,172,518**	**160,270,121**	**77,595,721**	**89,242,375**	**24,180,732**
Load, MWH	**13,845,351**	**4,978,186**	**2,081,446**	**3,147,502**	**1,539,637**	**1,908,750**	**189,830**
Average Rate	**57.316**	**64.902**	**57.255**	**50.920**	**50.399**	**46.754**	**127.381**
Rate without Change	60.578	66.380	58.600	59.094	55.381	52.784	75.264
Pct Chg in Rate	**-5.39%**	**-2.23%**	**-2.30%**	**-13.83%**	**-9.00%**	**-11.42%**	**69.25%**

	Tukwila					
	Total	Residential	Small	Medium	Large	High Demand
Cost Share Rev.Reqmnts	65,825,469	9,973,765	4,576,079	11,999,573	14,519,103	24,756,950
Share of Cost Shr Rev Req	4.576%	0.693%	0.318%	0.834%	1.009%	1.721%
Wholesale Net Revenue	-14,533,276	-2,202,058	-1,010,330	-2,649,326	-3,205,600	-5,465,963
Other Adjustments	4,947,123	716,346	339,341	904,111	1,094,705	1,892,621
Tot Revenue Requirement	**56,239,317**	**8,488,053**	**3,905,090**	**10,254,358**	**12,408,207**	**21,183,608**
Load, MWH	**1,001,216**	**116,543**	**63,963**	**183,627**	**224,480**	**412,603**
Average Rate	**56.171**	**72.832**	**61.052**	**55.843**	**55.275**	**51.341**
Rate without Change	60.021	70.818	61.600	62.175	57.757	56.999
Pct Chg in Rate	**-6.41%**	**2.84%**	**-0.89%**	**-10.18%**	**-4.30%**	**-9.93%**

	Other Suburbs				
	Total	Residential	Small	Medium	Large
Cost Share Rev.Reqmnts	162,298,943	112,709,370	20,449,019	26,125,162	3,015,392
Share of Cost Shr Rev Req	11.282%	7.835%	1.422%	1.816%	0.210%
Wholesale Net Revenue	-35,833,171	-24,884,537	-4,514,836	-5,768,044	-665,753
Other Adjustments	8,277,423	5,330,257	1,157,860	1,603,587	185,718
Tot Revenue Requirement	**134,743,194**	**93,155,090**	**17,092,043**	**21,960,705**	**2,535,357**
Load, MWH	**2,049,243**	**1,317,004**	**285,830**	**399,788**	**46,621**
Average Rate	**65.753**	**70.733**	**59.798**	**54.931**	**54.382**
Rate without Change	66.476	70.150	59.700	60.410	56.247
Pct Chg in Rate	**-1.09%**	**0.83%**	**0.16%**	**-9.07%**	**-3.32%**

all rates. Hence, new residential rates start from what could be considered a 'biased low' base which means that comparisons of new rates with the current residential rate will have an 'upward tilt' because the base rate is 'artificially' low. The same is true for streetlights. Conversely, rate changes for medium and high demand classes, in particular, will have a 'downward tilt' because their bases are 'artificially high.' Adjusting for these biases indicates more uniformity among the results than Table 2.11 implies on the surface. As a first approximation, adding the difference between marginal cost rates and the gradualism rate for the residential class in Table 2.12 to the service territory result for residential class in Table 2.11 gives a result comparable to subtracting the difference for medium and high demand in Table 2.12 from the corresponding service territory results.[2] What this implies for the future is that there will be less disparity in percentage rate changes among classes now that gradualism's rather large distorting effects are eliminated. There will still be some differences in percentage changes in future rates that reflect true, underlying differences in, changes in the relative cost of service and the impact of franchise contracts, but the relatively large potential effects of gradualism will no longer distort the picture.

Table 2.12
Marginal Cost Rate Changes and Gradualism Adjusted Rate Changes
For rate year 2001, Cap = 6%, Floor=0%, from 1999 Rate Case

	Res.	Small	Medium	Large	High Dmd	StLts
Marg Cost Rt Chg	10.73%	3.13%	-6.52%	0.93%	-5.57%	29.05%
Gradualism Rt Chg	6.00%	3.15%	0.00%	1.93%	0.00%	6.00%
Difference	-4.73%	0.02%	6.52%	1.00%	5.57%	-23.05%

As explained in the ***2007-08 RRA***, streetlight revenue requirements are now estimated to be substantially higher than the last rate-case estimated. The current higher estimate of the functionalized revenue requirement assigned to streetlights combined with its large gradualism benefit in the last rate case indicated in Table 2.12 explain why that class has such a large percentage change in its cost per MWH.

[2] Residential = 1.47 + 4.73 = 6.10
Medium = 11.64 – 6.52 = 5.52
High Demand = 11.14 – 5.57 = 5.57

Chapter 3

Policy Framework

3.1 Introduction

The underlying policy framework for cost of service analysis has been stable for several rate increases. There have been some modifications in the past to the details of application, and there are some modifications for this rate case, but the basic policy continues in effect.

The basic policy governing the development of this document can be simply stated:

The allocation of City Light's revenue requirement to each customer class is based, in the first instance, on reliable, up-to-date estimates of the cost of serving each class.

The City informally adopted this policy after the first general rate increase in 1970 when it recognized that it needed some standard upon which to apportion the rate increase. The guideline was formally adopted in 1977 when the first rate-making policy resolution (Resolution 25469) was adopted.

From the beginning, a cost standard for revenue allocations was recognized as a guideline --deviations from this guideline were allowed if those deviations would accomplish some other goal. The first resolution talked about social objectives that "may justify giving special consideration to certain customers." It also recognized that in order to promote rate stability, deviations from the cost standard might be necessary. Indeed, this has been the case in every rate increase since the goal of cost-based rates was first adopted. This rate case, though, finally allows the cost-of-service based rates to set the standard and the only deviations from that reflect contract provisions.

The purpose of this chapter is to present an overview of the major policy framework that guides allocation of revenue requirements. Having an understanding of the environment in which the Department has operated and the evolution of policy in the past two decades provides assistance in understanding the current framework.

3.2 A Brief Informal History

Prior to 1970, and especially prior to the energy crises in the world associated with the temporary oil embargoes established by the Organization of Petroleum Exporting Countries (OPEC) in 1973 and 1978, hydroelectric energy was in abundant supply in the Northwest. City Light, along with other utilities in this region, encouraged increased consumption of electricity in a variety of ways. It promoted "all electric" homes. It promoted consumption with declining block rates, particularly to customers with the potential for large consumption such as commercial and industrial customers.

The OPEC energy crises changed the outlook for energy in most parts of the world and here in the Northwest. The increased prices of fossil fuels that followed the OPEC embargoes caused many energy customers to shift to electricity. That increase in electrical load led to a region-wide concern that the surplus of hydroelectric power would vanish many years sooner than formerly predicted. The region began planning to acquire a number of nuclear-powered generators to support the projected load growth. City Light began acquiring conservation resources and additional generation resources in the early 1980s as a response to the changed outlook for electricity.

As it turned out, the imminent end of the surplus of regional hydroelectric power did not occur in the 1980s. Electrical price increases, associated with increased cost of nuclear and other resources acquired, dampened demand. Additionally, significant national economic recessions had ripple effects in this region so that demand pressure on energy resources declined for awhile. For these reasons, it was then expected in the 1980s that the regional surplus of hydroelectric energy would likely last until the early or mid-1990s.

Though the 1980s led to an abatement of the fear of imminent end of the regional surplus of energy, regional planners and policy makers, including those with City Light, saw a need to begin changing their policies. Economic theory and economic price signals needed to be more strongly integrated in planning, operations and pricing. Policies related to resource acquisition, as one example, were sharpened in those years when it was anticipated that additional resources would need to be acquired. Potential resources began to have their benefits measured by an estimate of the marginal cost of acquiring additional energy from known generating resources. Similarly, it was clear that revisions were needed in the designation of the customer classes, policies related to cost (or revenue requirement) allocation among customer classes and rate design principles. Economic logic indicated that customer classes at City Light should be defined by similarity in the cost of serving the customers, rather than by the nature of the end-use of the electricity. Economic logic leads to prices set equal to marginal costs. Prices for a municipal utility, however, recover only costs. The best approximation to the theoretically optimum price was to set the average level for rates by class by allocating revenue requirements in proportion to the marginal costs imposed on the Department by each customer class. Finally, rates were set to provide, in so far as practicable, a marginal cost signal to each customer class in order to promote efficient use of electricity.

Structural changes to the national and regional electrical industry were unfolding at the same time as these various external shocks to the economy and to the petroleum industry. These structural changes provided further support for the policy changes noted above. Prior to the late 1970s, the electrical industry was characterized as a collection of vertically integrated monopolies. A typical electrical utility had monopoly control over its own generation, transmission and local distribution. Each utility had a geographically defined market area. The various utilities were regulated either by a state utility commission, if the utilities were private for-profit companies, or by local government entities or local boards if the utilities were municipally owned or owned by a co-operative. This monopolistic character of the electrical industry began changing, however, in the late 1970s. At that time, Federal legislation opened the door for non-utilities to develop generation facilities and sell their output to utilities. More Federal legislation in the early 1990s removed the monopoly control over inter-state transmission enjoyed by the owners of those lines. Thus, two major parts of the electrical utility industry were opened to competition. Those changes supported the increased use of economic logic and theory in planning and operations by City Light.

The last segment of the industry, i.e., local distribution, has now opened in some states. In particular, it is now possible in some states for other parties to sell power to retail customers over distribution lines owned by someone else. California, for example, tried this experience, starting in 1995, but at the same time required retail distributors to sell their sources of power. California legislation at that time required power producers to state at what price they would make their power available to a state authority and required distributors to buy from the state authority which, presumably, had arranged for the least cost sources of power. The system that was set up, though, proved amenable to gaming and wholesale power costs escalated many-fold over previous levels, driving several companies into bankruptcy and causing enormous financial harm to many utilities on the west coast.

This adverse experience in California slowed down the march to opening the door to more retail competition. Since then, California has revised its legislation and some states are continuing with the experiment in one form or another. Texas started with a new set of regulations several years ago. Beginning Jan. 1, 2007, Texas law will give Dallas-based TXU Energy complete freedom to set its rates without any oversight from state regulators. TXU already is testing several electricity rate plans, which give customers a choice of lower rates pegged to natural gas prices or a steady rate that in the bargain commits the customer to staying with TXU for up to two years.

Overall, the electricity industry has changed significantly over the past several decades and more changes may occur in the next decade, such as development of some form of regional transmission organization. All these changes support the notion that electric utilities need to be able to estimate as accurately as possible the costs of providing services to its customers, and then to set rates accordingly, so that they can best serve the customers.

In addition to the changes in the electricity industry, City Light signed fifteen-year franchise agreements with four cities in the late 1990s (Shoreline, Burien, Sea Tac, Lake Forest Park) and agreed to a revised franchise agreement with Tukwila in 2002. These agreements require some changes in the way City Light deals with suburban customers. The first four franchises grant City Light "the right, privilege and authority … to construct, operate, maintain, replace and use all necessary equipment and facilities for an electric light and power system" [located within each of the four cities]. In exchange for this exclusive right to provide electrical service, all of the contracts require City Light to make payments to the suburban city governments based on the energy portion of revenue collected from customers within those cities. The franchise contracts also contain a provision that, pursuant to a rate review process conducted by the Seattle City Council, City Light has the prerogative to charge a premium to customers in those cities. This premium can be no "greater than an eight percent differential in the power portion of the rates to customers in [those cities], compared to the power portion of rates charged to similar customers in the City of Seattle."

The more recent revised agreement with Tukwila has strong similarities to these other four agreements, but requires City Light to make payments to the Tukwila City government based on the energy portion and on the distribution portion of revenue collected from customers within Tukwila. In addition, the Tukwila contract provides prerogatives to charge premia on both the power and distribution portions of rates charged to similar customers in the City of Seattle. The maximum energy premium was seven percent by the years 2005 and 2006, rising to eight percent in 2007. The maximum premium on the distribution (non-power) portion was five percent in 2005 and 2006 and six percent as of 2007.

Since City Light is a Department of the City of Seattle, its primary mission must be identified as serving its Seattle citizen owners and Seattle customers. The advent of the new franchises indicates that suburban customers must now be viewed differently than Seattle customers.

3.3 Long-Term Rate-Setting Objectives

Resolution 27726--the policy resolution for the 1989/90 rate review adopted in November 1987--and Resolution 28004--adopted July 24, 1989, and reaffirmed in Ordinance 116291, adopted July 31, 1992--lists nine long-term rate-setting objectives. City Council in the spring/summer of 2004 considered rate setting objectives again. Council staff at that time recommended that the long term objectives adopted in 28004 were ". . . consistent with current policy goals of the Council and . . . could be included without revision in a new rate." Three of these nine objectives deal directly with cost allocations:

° **Customer Payment Based on Cost of Service.** Rates should be based on the costs of service to the customer. Rates should reflect changes in the costs of service over time.

° **Equity**. Rates should reflect a fair apportionment of the different costs of providing service among groups of customers.

° **Rate Stability**. Rate levels and rate structures should be changed in an orderly manner over time.

Each of these long-term rate-setting objectives is discussed below.

3.4 Customer Payment Based on Cost of Service

The objective of basing rates on costs of service can be achieved through either a marginal cost or an average (embedded) cost methodology. Both of these methodologies are generally regarded as providing appropriate cost standards. In addition, both methodologies will track cost changes that occur with the passage of time. However, marginal cost estimates are much faster to respond to changes in technology and the price of inputs, while embedded cost estimates reflect cost shifts in a much more gradual fashion.

The various cost figures that are calculated in this report establish City Light's best estimates of the marginal costs of serving different classes of customers. The previous chapter briefly discussed the manner in which revenue requirements are allocated on the basis of class' shares of marginal costs. In this manner, only the amount of revenue needed to cover the Department's cost of service is collected and each customer class contributes its proportionate share of that revenue requirement. The next chapter discusses this allocation process in more detail.

3.5 Equity

In all of the rate increases since 1980, City Light has grappled with difficult equity issues that influence how cost of service is determined. Since rates based on cost of service are designed for customer classes, the make-up of customer classes must be understood.

3.5.1 Definition of Customer Class – 1

The definition of customer classes (i.e., groups facing the same rates) has changed over the past two decades. Prior to the mid-1980s, the type of customer generally defined customer classes. But, as explained in the short section on history, changes in the external environment in the 1970s, i.e., major oil price escalation, and significant national recession, indicated that new definitions of classes were needed. The intent of the change in customer classes was to group customers on the basis of the costs they imposed on the Department to provide service to them. Rates to these classes were to reflect the costs to the Department. Such a cost-related definition of customer classes and rates appeared to be equitable.

At the same time, there was a concern that instant adoption of these new policies related to definition of customer classes and rates could lead to disproportionately high rate increases for some customers. Two methods were used to confront this problem.

One method was to keep some customers separated into separate classes (or sub-classes) even though the costs to serve them were similar, e.g., the "standard" and "industrial" classifications for medium, large, and high demand general service classes. There was a policy goal to remove these sub-class designations eventually, which has now been achieved, but maintaining those distinctions was helpful in making a transition from the old, inherited rates.

A second method to treat too rapid increases in rates for a class relative to other classes was "gradualism."

3.5.2 Gradualism

Ultimately, allocating revenue requirements based on marginal cost shares is a goal of the utility. However, it was recognized at the time that the rate-making process was shifted to reliance on setting initial rates based on each class's contributions to the cost of providing service that cognizance needed to taken regarding the potential size of rate changes for the different customer classes. Significantly different changes in specific customer rates relative to rates of change for other customer classes was deemed to be inequitable. A balanced treatment was needed in order to make the transition to classes and rates based on sound economic rationales and, at the same time, allow a reasonable length of time for the customers who would be affected the most significantly by the new policies to adapt to the changes. In the 1986 rate process, a policy of "gradualism" was used to moderate the rate increase to be incurred by any class. This policy had been used in earlier rate increases, and has been used in every rate case since.

For the 1986 rate process, cost of service-based revenue allocations would have resulted in about 30-35% increases for the medium and large industrial customer classes, compared to a system-wide increase of about 9.5%. On the other hand, residential and commercial classes would have had increases at or below the system average. The Mayor's recommended revenue allocation presented to the City Council recognized this as an equity issue and proposed a divergence from pure cost-based rates, with the increase for the medium and large industrial classes falling to the 20-25% range, and the medium and large commercial classes making up the difference.

In its deliberations for that rate case, the City Council took into consideration precarious financial conditions for several major industrial customers and the prospect of major losses of jobs and income in the Seattle area. The Council adopted a "gradualism rule" that limited the 1986 average class rate increase to 1.5 times the system rate increase. As a result, the medium and large industrial class' rate increase was limited to 14.3%. The cost of applying this rule was absorbed proportionately by all the other customer classes.

In the 1989/90 rate case, the customers classified as "industrial" faced the largest rate increases. These ranged from 15% to 22% in the industrial classes for full cost of service allocation. The rates adopted by the City Council employed a gradualism rule which capped any class increase at 2.0 times the percentage increase for the entire system. Since the system rate increase was 4.4%, this meant that no class would receive an increase of more than 8.8%. In addition, the residential class, with the highest rate of all classes (except for Streetlights), was kept at its cost of service level, meaning that it absorbed none of the revenue burden being transferred from capped classes to other classes. Again, equity issues played a role in guiding final decisions.

In the 1993/94 rate case, industrial customers again faced the largest rate increases, which ranged from 20% to 27% for full cost allocation, when the system average increase was 12.6%. A gradualism rule which capped any class increase at 2.0 times the percentage increase for the entire system left two sets of industrial customers with rate increases over 25%. The City Council invoked the equity issue to set the gradualism rule at 1.25 for this rate increase, which thereby capped the highest percentage rate increases at 15.7%.

In the 1995/96 rate case, average system rates rose 5.7% and 5.3%, respectively. Industrial customers and, for a change, residential customers, would have faced rate increases in the 9-11% range in each of these two years if full cost allocation had been used. The City Council used a gradualism cap of 1.25 to limit the maximum rate increase to approximately 6.6-7.2%.

In the 1997/98 rate case, the average system rate declined nearly 1.1% between the adopted rates for 1996 and the average system rate for 1998. Whenever the system average rate has a low percentage increase, or a decrease, gradualism based as a multiple of the percent change in the average system rate does not work. Consequently, a maximum percentage increase of 3 % between 1996 and 1998 was set as a gradualism rule. This cap appeared reasonable and was approximately half of the expected inflation between those years. Residential and Medium-Industrial customers had rate increases over these two years at the maximum level. Medium-

Standard customers had rate increases of less than 2.2% over these two years. All other classes had rate decreases, even after providing gradualism assistance.

The 1999 rate case was characterized by average system rate increases that were the equivalent of about 3 percent per year for each of the three years and two months covered in the rate case. That rate case established rates for two periods. One set of rates was established for an initial 26 month period then a second set of rates was established for the last twelve 12 months. Average rates for that rate case based on cost shares produced substantially higher rate increases for some classes whereas other classes had rate decreases. Hence, two gradualism criteria were adopted for that rate case in order to minimize differences in rates of change among customer classes while still reflecting changes in rates implied by the underlying, different, cost structures to serve the different classes. First, a 6 % rate increase cap was set for the first (26 month) period and a 9% rate increase cap was set for the last rate period. Second, a floor of no change from rates without a rate increase was adopted for both of the two rate periods.

The next table illustrates the impact of gradualism on the major rate classes for the first rate period in the last rate case. The first row presents rate changes associated with allocating revenue requirements by marginal cost shares. The second row illustrates the rate changes after the gradualism policy was applied. The third row presents the effect of gradualism, i.e., it shows by how much rates were changed because of the gradualism adjustment. Residential rates were held down by 4.7 percent compared to what their rates otherwise would be. Streetlight rates were held down by 23 percent. Medium and High Demand classes, by contrast, had rates increased by 6.5 and 5.6 percent, respectively.

Rate Changes for First Rate Period in 1999 Rate Case

	Residential	Small	Medium	Large	High Dmd.	Street Lts.
Marg Costs	10.7%	3.1%	-6.5%	0.9%	-5.6%	29.0%
Gradualism	6.0%	3.1%	0.0%	1.9%	0.0%	6.0%
Difference	-4.7%	0.0%	6.5%	1.0%	5.6%	-23.0%

The rates established in the last formal rate case were shortly overtaken by the adverse developments in the wholesale market mentioned above. There have been ten changes in rates since the last rate case. Except for an adjustment to network rates proposed for the second rate period in that rate case, all current rates start with the gradualized rates from the first rate period in the last rate case. All of the initial rate changes since then were increases in the form of surcharges. Some of the subsequent rate changes have introduced small decreases in rates. All of the changes were based on relatively simple increases or decreases per kWh based on changes in power costs. This rate case reverts to the traditional method of changing rates, i.e., examining all the costs associated with providing service. Importantly, however, this rate case finally dispenses with the use of gradualism adjustments. A goal of the rate-making process has been achieved as of this rate case.

3.5.3 Definition of Customer Class – 2

In the 1997/98 rate case, it was possible to coalesce the standard and industrial subclasses for the large and high demand classes. The percentage changes in rates for those subclasses were less than the maximum, even after providing gradualism assistance to residential and medium-industrial customers. This coalescence into the larger classes accomplished a cost of service objective set for these sub-classes more than a decade previously.

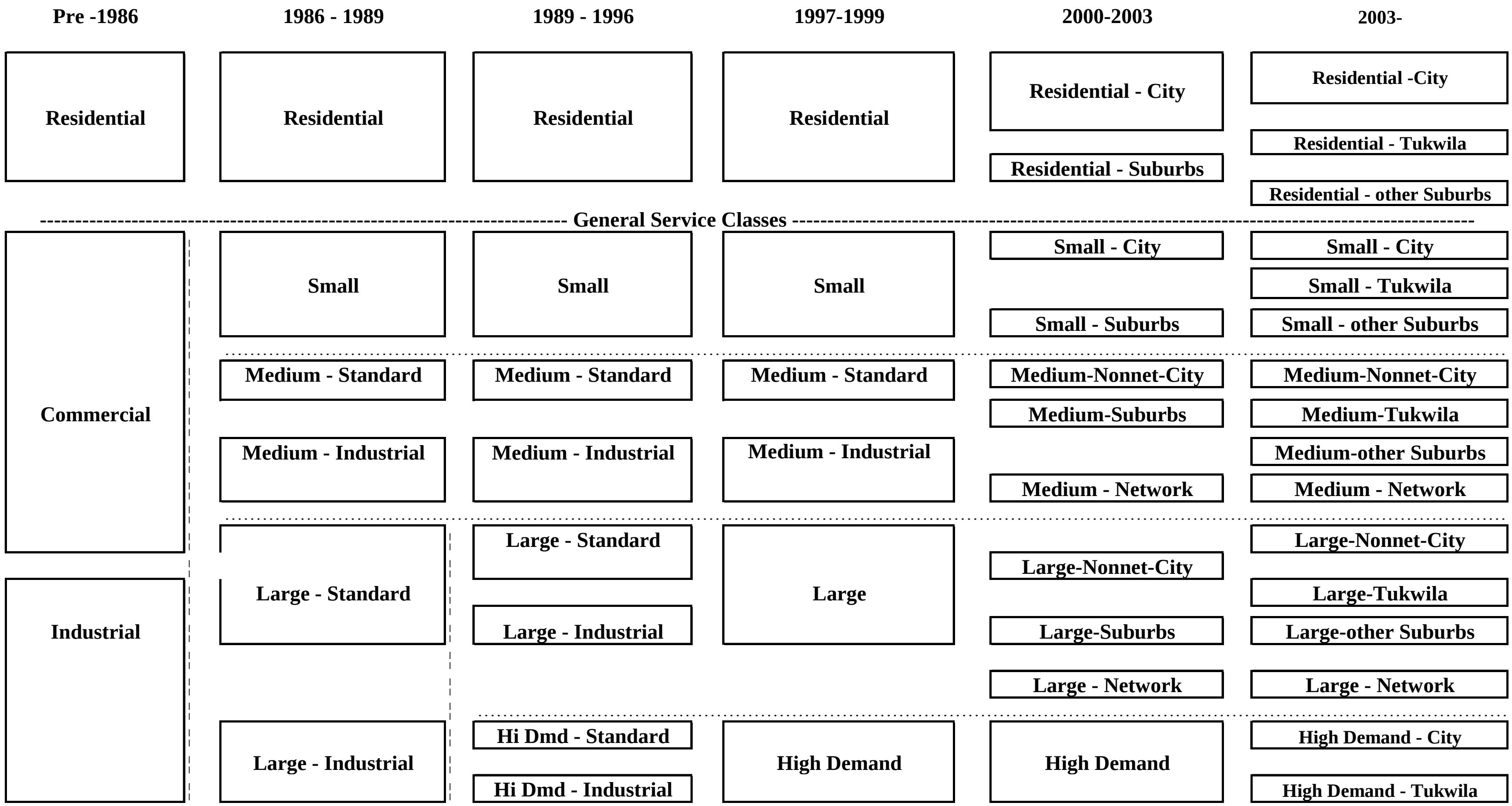
Further refinements in classes based on cost of service were adopted in the 1999 rate case. One of these was, finally, to remove the standard and industrial subclasses for the medium general service class. This change completed the goal of removing those particular non-cost-based distinctions. But other cost-based distinctions became apparent. One separated the suburbs (excluding Tukwila because of the nature of its franchise agreement with Seattle at that time) from Seattle. These suburban customers could no longer be considered captive customers in the same manner as Seattle residents. These Suburban customers have the legal option to form their own utilities or to seek power from some other source.

Another cost-based refinement in classes was separation of the downtown network from other customers. Network service involves provision of redundant feeders, network protectors and other equipment to provide more reliable service than standard radial service. The 1999 rate case introduced separate rates for the larger customers on this downtown network because of these higher costs of service. Costs for providing service to smaller customers in the network (Residential and Small General Service customers) were estimated but were then consolidated, along with their loads, with their Seattle non-network counterparts so that the larger network customers would not be subsidizing the smaller network customers.

This rate case is similar to the previous rate case regarding customer classes but Tukwila and Seattle replaced their previous franchise agreement on May 1, 2003 with a new agreement. The new franchise agreement with Tukwila stipulates that the Department will pay Tukwila an amount each month in exchange for Tukwila not developing their own municipal utility. The agreement also permits the Department to set rates to customers in Tukwila that, in 2006, have power-related rates that are up to seven percent higher than corresponding customers in Seattle. This differential rises to 8 percent in 2007. The agreement also permits distribution-related (non-power) rates that are up to five percent higher than corresponding customers in Seattle in 2006 and six percent higher as of 2007. Initial percentage differences when the new franchise agreement took effect were different. Thus, with the advent of the new franchise agreement in 2003, separate rates were established for Tukwila.

Figure 3.1 presents a simplified over-view of the evolution of customer classes in recent years. Residential rates, in particular, have both a standard rate and a lower rate for low income and disabled customers.

Figure 3.1
Evolution of Rate Classification System



3.6 Rate Stability

Stability is a desirable feature of rates because it facilitates customers' long-range planning and contributes to rational decision-making for energy investments.[3] Rate stability was recognized as an objective in the City's first rate-setting policy resolution (Resolution 25469, 1977) with the statement that:

...because of their impact on consumers--and because of their value in encouraging the most efficient use of existing capacity and in timing and financing future expansion--as much as practicable rate levels and rate structures should be changed in an orderly manner over time.

Concerns about stability entered into a mid-1980's decision to use a 20-year rolling average in the calculation of the marginal value of energy. It was felt this would help prevent abrupt shifts in the values of energy, and hence in cost shares assigned to classes.

During the spring of 1987, the City Council Energy Committee conducted an *ad hoc* review of City Light's cost allocation methodology. While several concerns were raised by interested parties, such as appropriate definitions of customer costs and the length of the marginal value window, the Committee felt that stability of process and rates was of greater importance than making any major methodological changes for that rate review.

3.7 Other Long-Term Rate-Setting Objectives

The other long-term objectives specified in Resolutions 27726 and 28004 were revenue requirements, efficiency, financial stability, economic development, social policy, and public involvement. Three of these--financial stability, social policy, and public involvement--do not have a direct bearing on the choice of a costing methodology. The use of gradualism to mitigate the impacts of rate increases (mentioned in the social policy objective) may affect the actual adopted cost and revenue allocations, but does not replace the costing methodology which is used as a basis from which to make the policy decision.

Economic efficiency is indirectly affected by the choice of a cost of service methodology. The City's policy is that the marginal cost framework for cost of service analysis and revenue allocations promotes economically efficient utility and customer decisions. The

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[3]See, for instance:

R.C. Carlson, "Impact of Electric Rates on Tacoma's Economic Development: Phase I," SRI International, May 1983.

P. Taylor and M. Hirsch, "The Significance of Electric Energy Costs to Industrial Firms in Arkansas," Public Utilities Fortnightly, July 27, 1985.

Tom Trulove (Northwest Power Planning Council member), NWPPA Annual Rates Conference, July 1987.

rate structure is usually the direct vehicle by which the efficiency objective is addressed. Rate design, not cost allocation, determines the rate structure, but some of the intermediate results of the cost allocation process are used in determining or evaluating rates.

Economic development is another long-term rate-setting objective. Economic development was a major issue in the 1986 rate process. As requested by the City Council in its resolution establishing City Light's work program for the 1986 rate review (Resolution 27103, June 1984), the Department contracted with Arthur Young and Company in November 1985 to analyze the impacts of electrical rates on economic growth. Among other things, the study concluded that stability and predictability of rates and rate changes are more important to business than the absolute level of the rates. Furthermore, immediate negative effects in terms of job and income losses from a rate increase are likely to be experienced only in energy-intensive firms that are already in a difficult market, running on razor-thin profits (or near-term losses), or are on otherwise shaky financial grounds. These negative economic development effects cannot be mitigated by class-level cost allocations (unless the specific firms are somehow defined into a class all by themselves). Rather, rate design as a first level of effort and, ultimately, specifically targeted rate relief will be necessary to achieve near-term economic development targets.

The Arthur Young study showed that rate increases do cause a net job and income loss to the area, all other things being equal, but the losses are very small in percentage terms compared to the size of the area's total economy. From the long-term perspective of economic development, total revenue requirements are likely to have the most effect, as revenues required from ratepayers are not available for other productive uses. In either case--near-term or long-term--economic development does not appear to be directly affected by cost allocation methodology.

3.8 Changes in the Policy Framework in Previous Rate Reviews

While the basic policy of cost-based rates has remained unchanged since 1970, the details of the policy framework have changed over time. Changes over the past two decades and changes introduced in this current rate case are discussed here and in the next section.

The 1986 rate review saw three major changes to the cost of service and cost allocation framework. First, the customer classification scheme was changed for nonresidential customers from classification by type of business to classification by the magnitude of the customers' monthly maximum demand. This new classification structure has been in effect since the adoption of the rate ordinance in 1986.

The second major change was in the methodology used to estimate the marginal values of energy which City Light uses to value the cost of providing generation, transmission, and distribution services to its customers. The new process recognized the near-term regional energy surplus and the longer-term necessity for building additional thermal generation facilities after the surplus disappeared in the 1990's. The new marginal values of energy were based on a 20-year "window" that incorporated both the near-term low costs of energy based mostly on existing hydropower and the future high costs of bringing new thermal facilities on-line to meet future load.

Finally, in 1986, a "two-step" cost allocation process was abandoned. The City began using a method of "proportionate shares" for revenue allocation, whereby the revenue requirement assigned to each class was in direct proportion to its share of the total cost of serving the Department's customers (Resolution 27266). It was felt that the proportionate shares approach could better meet equity and rate stability goals, and that growth cost issues and conservation objectives could be better achieved through rate design.

Resolution 28044, adopted in 1989, reaffirmed this basic policy framework for performing cost of service analyses.

Adjustments to the cost allocation policies made in the 1997-98 rate case responded to the increasingly competitive electrical industry environment. With the advent of wholesale marketing of power and the perceived threat of potential retail competition, it became important to track costs by sub-components. Such tracking permitted a better understanding of the underlying cost structure of the Department and permitted an efficient and equitable allocation of those costs (i.e., revenue requirements) among customer classes.

Total revenue requirements were divided into four major functional categories: energy, distribution, customer services, and public purpose programs. Each of these functional categories was then allocated among customer classes based on shares of appropriate marginal costs.

Additionally, it was recognized that whatever the outlook for energy prices in the future, economically efficient near-term decisions about consumption should be based on near-term values for energy. Economically efficient investment decisions about long-lived equipment that uses electricity should incorporate expectations about future prices, but the information about projected future energy prices could be provided directly, as an explicit forecast, without diluting the near-term price signal used in determining near-term cost allocation and retail rate-setting. For that reason, a shift was made to use near-term values for energy in calculating the marginal costs of energy to serve each customer class.

City Light also incorporated estimates of the costs of environmental externalities associated with energy production in its analysis. This decision reflected the support City Council has given to environmentally sound planning for many years. The Department evaluates potential new resources with alternative sets of planning values for energy that exclude and that include costs of environmental externalities. Decisions about new resources, including conservation, are typically justified when environmental externality costs are included in the evaluation. The Department, therefore, recommended, and Council approved that it be internally consistent in its use of environmental externality costs in both resource evaluation and in the cost allocation/rate setting process.

Inclusion of the environmental externality costs in its analysis of allocating revenue requirements, of course, had no effect on the average system rate, since that is dictated by the total revenue requirement and the total load. The inclusion or externality costs in the analysis only altered assignments of revenue requirements (slightly, as it turned out) among customer classes. Those classes that use proportionately more of their annual energy at times when environmental costs are highest had (slightly) more energy revenue requirements assigned to them. This assignment of revenue requirements increases both economic efficiency and economic equity.

The last rate case in 1999 introduced three changes in policy, as well as some revisions of assignment of certain components of revenue requirements and marginal costs. Two of these policy changes reflected new or previously existing cost-based differences in serving specific customer groups. These were the policies to treat suburban and large, downtown network customers as separate rate categories. The third policy change was a shift in the responsibility for paying for streetlights in the City of Seattle from the Seattle General Fund to all Seattle customers. City Council transferred ownership of about 17,000 streetlights from the Transportation Department to City Light in 1999. The new policy applied the costs of all streetlights that otherwise would be billed to the Seattle General Fund to customers who pay rates for the City of Seattle.

3.9 Changes in the Policy Framework

A legal ruling since the last rate case determined that transferring costs of streetlight services from the Seattle General Fund to City Light customers within Seattle was not appropriate. Consequently a change in this rate case is the reinstatement of all the costs allocated to streetlights to all streetlight customers, which includes in large part the Seattle General Fund.

Another change, less than in the framework and more in detail, is an increase in the number of revenue requirement functions allocated by their own marginal cost shares. This change reflects two things. One is a desire to allocate functional revenue requirements by cost shares that are as applicable as possible, rather than melding several revenue requirement functions into one category. The other is that in the last rate case, network rates were introduced for the first time, and it was not certain at the outset that network rates would be adopted. For that reason, the last rate case had to start, as had been the case in previous rate cases, with the presumption that all customers would be treated as if they were radial distribution customers. At that stage of the analysis, revenue requirements were allocated by four sets of shares.

The cost of service to network customers had been the subject of a special, detailed study the year before the last rate case. That study utilized eleven shares of marginal cost to allocate revenue requirements. At an appropriate place in the last rate case, summary results from the special study were introduced in order to adjust the revenue requirements assigned to network and non-network customers. This adjustment also took into account policy decisions regarding the extent to which the incremental network costs (above nonnetwork costs) would be paid for by network customers with the balance picked-up by non-network customers.

This rate case, unlike the previous rate case, starts with network customers so that the general outlines of that previous external, special study need to be incorporated from the outset. The number of shares, here, has been reduced to ten from eleven in the special study. Revenue requirement for long distance transmission was allocated based on its own share whereas that revenue requirement has been combined with other energy revenue requirements in this case since the cost shares did not differ significantly.

Another change, again in details, occurs in the treatment of net wholesale revenue in revenue requirements. In the last rate case, the net revenue was, in fact, a relatively small net expense rather than a net revenue. At that time, it was treated as a component of energy revenue requirements. Since that last rate case, the Department has acquired, via contract, significantly more resources so that net wholesale revenue is now expected to be a substantial, large number. Since the additional resources were acquired to provide service to all customers, and not just the customer classes with the most intense use of energy, a decision was made that revenue requirements would be functionalized along cost bases initially excluding net wholesale revenue. Those initial costs would be allocated based on cost shares and subjected to subsequent policy adjustments indicated above. Then, as a final step, the net wholesale revenue would be allocated among customer classes based on each class's share of the costs allocated based on cost shares.

Chapter 4

Overview of Cost of Service Methodology

4.1 Introduction

This chapter provides an introduction to the framework used to allocate functionalized revenue requirements among customer classes. The framework begins with determining how much it costs City Light to serve various types of customers. Two major aspects of the framework are discussed initially. One is the methodology to be used in estimating and applying costs to the rate case. The other is a discussion of the functionalized revenue requirements and the specific cost elements whose shares are used to allocate them.

The fourth section discusses a change in the details of the functionalization of revenue requirements and a resulting, necessary, change in dealing with those details in the cost of service. The following section continues with a brief discussion of cost adjustments that reflect policy guidance and terms of contracts with several franchise cities. The next section then summarizes the general steps used in allocating revenue requirements among customer classes.

The final two sections discuss general issues that pertain to a number of cost estimations. One topic is the treatment of inflation so that all cost items over time are put on the same cost basis. The other topic is conversion of capital costs into annualized costs.

4.2 Marginal Cost versus Average (Embedded) Cost

The first choice made in a costing study is whether to use marginal costs or average costs. A marginal cost approach was used in the last nine City Light sets of rate changes (1980, 1982, 1984, 1986, 1989/90, 1993, 1995/96, 1997/98, and 1999). The City Council directed City Light (Resolution 27726, passed in December 1987) to continue to use a marginal cost framework in the cost of service analysis for the 1989/90 rate increase. The Chair of the Council’s Energy Committee reaffirmed this decision after a review of costing procedures conducted during the first quarter of 1987. And this decision was again reaffirmed in Resolution 28004, passed in July 1989, that directed City Light to continue to use a marginal cost framework in future rate cases.

Marginal costs measure how a utility’s cost picture changes when new load is added and/or new customers join the system. **Average costs** are derived by dividing a utility’s total costs by total load, maximum demand, or the number of customers. Both methods are recognized by the courts, by regulators, and by the utility industry as valid approaches. The two methods will generally lead to different cost estimates though, in principle, if average costs are minimized marginal costs equal average cost.

The information content of the two measures typically differs in practice. Average costs are derived from historical accounting costs with known and measurable changes, that, in turn, reflect current (or test) year operating expenses and the accumulated (annual) investment costs of the entire stock of capital. In an average cost approach, plant values and interest expenses on individual capital items will vary widely depending on their vintage and the interest rate and price structure prevailing at the time they were acquired. The accounting values are a composite of this entire profile. Marginal costs, on the other hand, measure only the cost changes associated with a change in load or in the number of customers. Only current (or near-term future) costs are included in the marginal cost estimates.

Both cost methodologies utilize accounting data but the embedded cost approach also relies on the historical cost of capital plant whereas the marginal cost approach looks at current or expected costs. The conventions for how to report accounting data are well developed and slow to change. Consequently, one might expect more uniformity in the treatment of accounting data in an embedded cost approach than would be the case in marginal cost data. Consistency in the treatment of data is a desirable feature in cost allocations because it promotes stability. It cannot be said, however, that embedded cost methodologies involve fewer significant choices. Accounting conventions still leave significant leeway in how capital costs are annualized. Those who use an average cost methodology must still choose among a wide variety of methods of classifying costs as energy, demand or customer-related, and face many different options for allocating costs to classes.

Several decades of debate over the two approaches has not produced agreement within the industry on whether one approach is better than the other. Each utility and each regulatory body has its own set of reasons for its preference. In Seattle's case the choice was largely the product of the set of circumstances existing in the last half of the 1970's. The City and the region enjoyed low average rates but faced very high costs for new resources. Energy shortages were forecast, despite an aggressive construction program, in part because demand was being fueled by low rates. The City was determined to avoid being blinded about the future by the low level of the current rates. Given this determination, the choice of a costing methodology was clear, since a marginal cost approach provided a much better indication of the direction of change. In retrospect, the choice was fortuitous in that the next major issue to emerge in the region—an energy surplus—was also an issue with significant financial implications that could be tracked by marginal cost calculations.

After the decision was made to use marginal costs, other reasons emerged to support continuation of the framework. The framework provided an ideal tool for making resource evaluations for a wide range of generation and conservation projects. The marginal cost calculations also provided guidelines for the design of rates and a means for assessing the economic efficiency of rate options. Moreover, the framework could be used to identify the amount of "economic rent" from the hydro system—in other words, the methodology could be used to quantify the hydro benefits enjoyed by ratepayers. Finally, of course, since a marginal cost approach has been used in every rate increase since 1980, consistency with past practice and the desire to create stability in the rate process became important arguments for its continuation.

One further argument in favor of the marginal cost methodology is that it provides the most useful information to decision makers in a competitive environment. Historically, the electric utility business was characterized as a collection of vertical monopolies regulated by either state or local groups. Typically, each utility had a generation arm, a transmission arm, and a local distribution arm. Each utility was confined to serving customers in a specific geographic area; it was a local monopoly whose prices were regulated by some regulator outside the utility. In this environment, the question became how to get permission to make capital expansions in order to enlarge the cost basis upon which rates, and profits, were set and, then, how to allocate that cost base among customer classes.[4] If a proposal could "get by" the regulators, then the proposal was administratively acceptable to the utility regardless of the inherent economic logic of the proposal.

In a competitive environment, however, just "getting by" regulators is no longer sufficient. In a competitive situation, it is necessary to judge each spending decision in light of the earnings that can result from that decision. This judgement is, simply, marginal cost analysis. Even though the push to deregulate the industry prevalent in the late 1990s is no longer so evident, the need is as strong as ever for utilities to make 'good and competitive' economic decisions regarding both resource acquisition and pricing their product. So, it is important to have cost analyses based on marginal cost principles rather than average cost principles. Moreover, the new emphasis on separating out the component parts of the electricity industry implies a need to isolate actual revenue requirements and cost analyses into corresponding components.

4.3 Overview of Costs and Functionalized Revenue Requirements

Seattle City Light is in the business of assisting in the delivery or provision of many highly desired services, such as lighting, heating, cooling, and machine power. In general, it provides these services through electrical power delivered to customers who then use the power with equipment or facilities to produce the desired services. The amount of power desired is a function of, among other things, the demand for the ultimate services and the efficiency of the equipment for transforming the electrical

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[4] The text describes the situation for private--for profit--utilities. The situation for utilities that were not trying to maximize profits, such as City Light, was a little different; there was no attempt to enlarge the capital base just to increase rates. But, similar to the private utilities, the municipal utilities had little intrinsic incentive to determine the incremental cost of any given action to compare to the prospective earnings from the action.

power to the desired services. City Light, therefore, is involved in many activities in providing services to retail customers. First, there must be acquisition of bulk power either through owned generation, long term contracts or exchanges, or purchases from the wholesale spot markets, or assistance to customers in converting electrical power to ultimate services. City Light minimizes costs of providing ultimate services if improving the efficiency of transforming electrical power to ultimate services is less than the cost of providing additional electrical service directly. For that reason, costs of conservation are included as a component of power costs from the view of revenue requirements. All power-related revenue requirements are allocated based on costs of actual power and transmission. Actual power obtained for use by retail customers requires transmission to the local service area via high voltage lines. Once in the service territory, the power must be distributed and high voltage must be transformed to lower voltage for customer use which typically involves transformations at substations, with subsequent distribution through feeders, and further transformation at the customer's location. Next, individual customers must be connected, metered and billed. Finally, there are costs associated with adopted public policies, in particular costs associated with subsidies to low-income, senior, and disabled residential customers.

There are two major forms of local distribution. The more common form is radial distribution. Each customer is served by one distribution line. The other form is network distribution in which each customer is fed by more than one distribution line. Network service requires more equipment to serve each customer than radial service and, therefore, is more costly, but it provides higher reliability; outages of service because of malfunction or repair of equipment are rare.

Each of these activities has associated costs. Some of the costs are affected by the nature of the individual customer but other costs are not affected by the nature of the customer. For instance, the per-unit cost of bulk power is not affected by the nature of the final customer. However, since the market price of bulk power varies over the course of a day and throughout the year, customers with different load profiles but with the same total load face different total power costs. Additionally, the magnitude of energy losses involved in providing power to retail customers varies to some extent based on the size of the customer and nature of the distribution system (radial or network) serving the customer. These differences among customers affect power costs.

Distribution costs are functions of the size of equipment required to serve customers and that size, as well as its costs and losses from the equipment that increase in warmer weather, are affected by the load profiles of customers. Distribution costs also include streetlights, stoplights and floodlights. Streetlight costs are paid for, in the first instance, by City Light and many of these costs can be isolated in the process of developing the RRA. Some of these lights are a service provided by City Light for a governmental unit such as a city or county and others are purchased for use by specific customers. The costs of streetlight services provided for governmental units are passed on to the governmental units. Thus streetlights is both a distribution cost item because the costs can be identified at the RRA level and also a customer class[5].

Customer costs cover meter reading, billing, and other customer services. Larger customers, typically, receive more technical advice costing more than similar service to smaller customers.

In summary, costs for the above items are used to allocate among customer classes the revenue requirement items from the RRA. The next table indicates the shares of which cost items are used to allocate each of the individual revenue requirement categories.

Revenue Requirement Category	**Cost Items used to Allocate Revenue Requirements**
Energy	
Production	Power cost including long distance transmission
Purchased Power	Power cost including long distance transmission
Transmission - Long Distance	Power cost including long distance transmission
Conservation	Power cost including long distance transmission
Retail Service	
Total Distribution	
Transmission - In Service Area	Transmission - In Service Area
Stations	Stations
Wires & Related Equipment	Wires & Related Equipment by Nonnetwork & Network
Transformers	Transformers by Nonnetwork & Network
Meters, (except Meter Reading)	Meters, (except Meter Reading)
Streetlights/Floodlights	All costs assigned to Streetlights
Customer Costs	**Customer Costs**
Low-Income Assistance	Shares of Total of all costs

4.4 Treatment of Wholesale Net Revenue

The *Revenue Requirement Analysis* document describes how results from the Financial Planning Model (FPM) are converted into the functionalized revenue requirements indicated in the previous table. The large majority of the FPM items are various kinds of expenses that are assigned to one of the indicated revenue requirement items, however there are several revenue sources that provide cost offsets. These revenues reduce the amount that retail customers need pay for services provided by the Department. For these revenues to be properly treated by the cost of service model, they also must be

[5] Distribution costs associated with streetlights in the RRA are all assigned to the streetlight customer class in the COSM, as well as appropriate other costs, such as power costs and other distribution costs.

functionalized. In general, there are reasonable guidelines indicating which functionalized revenue requirement should be offset by each of the revenue sources. One revenue item, though, has grown substantially since the last rate case when it was of no material concern and now needs special consideration. This is net revenue from wholesale purchases and sales of bulk power. In the previous rate case, net wholesale revenue was projected to be -$14.5 million and -$19.2 million in 2001 and 2002, respectively. In other words, these net revenues were, in fact, net expenses and at that time were allocated entirely to functionalized energy revenue requirements. These projected net expenses in 1999 contrast with nearly $300 + million net revenue for the two year period 2007 and 2008 (see Table 2.2).

Growth of this net revenue is associated with the acquisition of a number of power resources since the last rate case to provide power, even in distressingly low water conditions, to all the Department's customers. All customers benefit when this revenue source is positive, not just those customers who consume large amounts of energy. For this reason, this revenue source was removed, initially, from the revenue requirements. The allocated revenue requirements, excluding the net wholesale revenue, indicated in the previous table are allocated based on shares of the cost items mentioned, then this net wholesale revenue offset is apportioned among all customer classes on the basis of the shares of the allocated revenue requirements.

4.5 Policy and Contract Term Adjustments

4.5.1 Network Cost Adjustment

Network service, using several feeders and network protectors and other specialized equipment to serve each customer, costs more per customer than radial distribution service. Separate rates for network customers were established in 1999. In order to provide a bridge between previous rates paid and the rates implied by full cost-of-service for network customers, a policy was adopted that passed on only 25 percent of the increased cost of network service to network customers in 1999. The cost differential percentage, though, was increased to 50 percent for rates starting in March 2002. This rate case allows, finally, for a 100 percent pass-through of network costs to network customers.

4.5.2 Gradualism

Gradualism has been a policy tool designed to allow flexibility to meet the sometimes conflicting objectives for the rate process set out by Council Resolution 28004. These objectives include, among others, equity, efficiency, rate stability, economic development and social policy. In practice, gradualism assigned boundaries to allowed percentage changes in rates so that there was not undue differences in rate changes among customer classes while at the same time allowing the effects of rates determined by cost allocation to be evidenced to the degree possible.

This rate case marks the end of a long process and, finally, eliminates the use of gradualism. It was not clear at the start of analysis for the rate case whether gradualism would or would not be used again. Hence, a gradualism tool was integrated into the cost allocation process, but as it turned out, it was not necessary to utilize the tool.

4.5.3 Franchise Contracts

Suburban franchise contracts were signed with Shoreline, Lake Forest Park, SeaTac and Burien in the late '90s. These contracts require the Department to pay the suburban cities six percent of the energy-related revenue collected from customers in those cities. The contracts permit the Department to increase the energy-portion of rates to customers in those cities by eight percent if the Seattle City Council approves in a regular rate case proceeding. These rate differentials were taken into account in the last rate case analysis and revenue requirements associated with energy were increased to reflect the allowed contract differential. This act increased total revenue that would be collected ($1,426,000 for 2001) and the extra amount was credited to those considered to be the owners of the Department's assets, viz., Seattle residential customers.

As mentioned before, there have been a number of rate changes since the last rate case. Each of these changes represented 'simple' changes to the energy costs for all customers that did not differ between Seattle and the suburbs. Thus, the current suburban rates have less than an eight percent differential over the energy costs of Seattle customers. This rate case proposes to reinstall the permitted energy cost differential.

Tukwila has had a franchise agreement with the Department for many years. As of the last rate case, that agreement required rates to customers in Tukwila to be the same as rates to Seattle customers. Tukwila renegotiated their franchise agreement in 2003 to reflect, in general terms, the other franchise agreements described above. However, the Tukwila franchise contract calls for the Department to pay the City of Tukwila amounts on both the power and distribution portions of the revenues collected from customers in Tukwila. By like token, the contract permits the Department to increase the power and distribution portions of rates to Tukwila customers relative to corresponding rates to Seattle nonnetwork customers. Similar to the other franchise adjustments, incremental revenue from rates to Tukwila customers is credited to Seattle residential customers.

Rate adjustments since the Tukwila franchise contract became effective have reduced the percentage differentials between Tukwila and Seattle rates slightly below what is permitted in the contract. This rate case proposes to reinstall the permitted differentials.

4.5.4 Consolidation of Network Residential and Small Classes with Seattle Nonnetwork Residential and Small Classes

The major beneficiaries of network service, it is assumed, are the medium and large customers within the network area. The cost of service and an allocation of revenue requirements is estimated for all classes within the network area. But as a final step in the allocation of revenue requirements, the revenue requirements and loads for the network residential and small customers are consolidated with the revenue requirements and loads for Seattle non-network residential and small customers. Thus, one set of rates is established for all residential and one set of rates for all small customers within Seattle.

4.6 Outline of Steps in Allocating Revenue Requirements

The process used to allocate revenue requirements among customer classes in this rate case is, generally, similar to the process used in the last rate case, but there are a few differences in detail that reflect some differences in circumstances. Summarizing the previous discussion, the major steps in the current process are the following:

(1) Determine the marginal cost per appropriate unit for
   (a) Energy, including long-distance transmission
   (b) In-service area transmission
   (c) Substations
   (d) Wires/poles/vaults
   (e) Customer transformers
   (f) Meters (except meter reading)
   (g) Customer costs

(2) Compute the total cost of providing each of the above services to each customer class in each year of the projected rate case when services are valued at marginal cost. Since this rate case sets rates for two years, add the marginal costs by class for the two years.

(3) Compute the share of the total marginal cost by type of service by customer class.

(4) Use these shares to allocate the sum of the revenue requirements for the two years that have been separated into corresponding functional categories

(5) Take account of the fact that most customers are served by radial and some by more expensive and more reliable network distribution systems. Rates for network customers, to date, have not recovered 100 percent of the revenue requirements that would be assigned to those customers based on shares of marginal cost. This rate case, however, permits 100 percent of network costs to be passed through to network customers.

(6) Take cognizance of contracts with suburban cities that require the Department to send payments to the governments of those cities based on the energy, or energy and distribution, revenues collected from Department customers located in those cities. Those costs are embedded in the revenue requirements. The same contracts permit, if the Seattle City Council approves, charging differentially higher rates on the energy, or energy and distribution, portions of rates to customers in those cities relative to corresponding customers in Seattle. Apply the allowed differential rates to the suburban customers. Follow previous policy direction that this incremental revenue from suburban customers be credited to Seattle residential customers.

(7) Follow previous policy direction that residential and small general service customers in the network rate area be charged the same rate as corresponding customers in Seattle. This objective is achieved by melding the revenue requirements and loads for these network customers with their counterparts in Seattle, creating average annual rates that apply to all similar customers.

(8) Distribute the revenue creedit from net wholesale energy purchases and sales among customer classes based on the allocation of revenue requirements based on cost shares (step (4)).

4.7 Inflation Rates

The numbers in this report are displayed in both constant-year and current-year dollar terms. Future year costs expressed in present day constant dollars can be interpreted as a projection of future costs if no general inflation occurs between the present and the future year--that is, if future dollars retain the same purchasing power as they have today. Usually, figures in this report associated with determining the marginal cost of providing services to customers are denominated in 2004 or 2005 constant dollars that are then converted to dollars of the year in question. All figures in the COSACAR model that are ultimately used to allocate revenue requirements among customer classes, regardless of the year's dollars in which they are originally denominated, are inflated to dollars for the year being analyzed for the actual cost allocation process, since the cost of service report is geared to each of those individual years.

Conversions of dollars from one year into those of another are made via the inflation index shown in **Table 4.11**.

Table 4.1
Inflation Index, 1982-84=100, and Annual Percent Change

2003	186.7000	1.467%
2004	189.6000	1.553%
2005	195.3000	3.006%
2006	200.4755	2.650%
2007	205.6878	2.600%
2008	211.2414	2.700%
2009	216.9449	2.700%
2010	222.3685	2.500%
2011	228.1501	2.600%

4.8 Annualization of Capital Costs: The General Case

In computing costs for generation, transmission, and distribution, a procedure is needed for annualizing capital costs. The capital investments in generation, transmission, and distribution equipment and facilities provide service for an extended period of time. For instance, a substation may have an economic life of 32 years, but the initial investment to build the facility is substantial. In lieu of charging all the capital cost in the first year of operation, the costs are spread (or annualized) over the economic life of the substation. In this way, the capital costs of the plant are recovered over its economic life.

The process of converting the total initial cost of an asset to a series of annual costs is usually referred to as annualization (the calculation of annual carrying charges). Rather than just dividing the total initial cost by the economic life of the investment, allowance has been made for the cost of capital over time. In other words, the present value of the sum of the annual payments has to equal the total initial cost.

Through annualization, the capital costs of City Light's capital investments are distributed or annualized over the economic lives of those investments to account for their use in any single year. The formula used in the calculation of the annual charges is shown below. (Detailed derivation of the annualization formula is shown in Appendix C of the *1989/90 COSACAR* and a similar derivation is presented in Appendix E of the *1983 Energy Resource Report Users' Guide*.)

$$AC = k\left[\frac{r(1 + r)^n}{(1 + r)^n - 1}\right]$$

where:

AC = annualized cost
k = investment (initial capital cost)
r = real discount rate
n = asset life in years.

This formula assumes that the annual costs occur at the end of each year. If costs are assumed to occur at mid-year, an additional half-year shift needs to be incorporated into the formula.

A real discount rate of 3% is assumed in this analysis. This discount rate is used in other financial analyses and represents the "real" cost of capital to Seattle City Light. For the purpose of this analysis, assumptions are made concerning the asset lives of generation, transmission, and distribution equipment and facilities. By applying these assumptions to the formula for annualized charges, annualized factors can be computed, which, when multiplied by the investment (k), will produce the annualized charge (AC) for the particular asset. The annualization factor is computed as follows for an asset with a useful life of 24 years:

$$AnnualizationFactor = \frac{r(1 + r)^n}{(1 + r)^n - 1}$$

$$= \frac{.03\,(1 + .03)^{24}}{(1 + .03)^{24} - 1}$$

$$= .05905$$

Thus, if the capital cost (k) is $100 and the asset life is 24 years, the annualized charge (AC) is $100 x .05905, which is $5.91 per year. In addition to annualizing the capital investments of energy-related facilities, the capital costs related to providing service to customers, such as meters, are also annualized by the same approach.

Table 4.2 shows the asset lives assumed for the equipment and facilities used in this study and the corresponding annualization factors. The asset lives shown in Table 4.2 are longer than those used in cost of service analyses prior to 1986. The asset lives are based on a study prepared for City Light by EBASCO Consulting Service (*Seattle City Light: Depreciation Study of Electric Plant in Service at December 31, 1980*). In its February 1985 *Financial Plan*, City Light recommended adopting the revised economic life figures from the EBASCO study. This recommendation was formally adopted by the City Council in its resolution on the *Financial Plan* in December 1985 (Resolution 27372).

Table 4.2

ASSUMED ASSET LIVES, DISCOUNT RATES AND ANNUALIZATION FACTORS*

Facilities	**Economic Life (years)**	**Real Discount Rate**	**Annualization Factor (AF)**
Transmission	45 years	3%	.040785
Substations & Feeders	32 years	3%	.049047
General Plant	28 years	3%	.053293
Transformers	30 years	3%	.051019
Meters & Service Connections (related to customer service)	35 years	3%	.046539

*In Table 4.2, annualized costs are assumed to occur at year-end and use the formula presented above. Computations for cost-of-service purposes presume that costs are incurred at the middle of the year so a half-year-shift to the above annualization factors is used. These values for the five assets lives indicated above are: 0.0401868, 0.0483271, 0.0525114, 0.05027077, 0.04585627, respectively.

Chapter 5

Load, Losses and Meters

5.1 Load Data

Revenue requirements associated with energy are the largest among all revenue requirements. These revenues are allocated based on shares of the marginal cost of energy. The energy involved is final customer load by class plus energy losses associated with getting energy from the generation source to the customer.

The basic allocation of revenue requirements is done by class for all nonnetwork classes and for all network classes. The nonnetwork load is then allocated to Seattle, Tukwila and the Other Suburbs, by class, based on share of total MWH by class. Though network residential and small classes are, ultimately, combined with their Seattle nonnetwork counterparts, they are initially considered as part of network load.

Tables 5.1 through 5.3 present MWH load information by two costing periods per month for the years 2007 and 2008. Table 5.1 summarizes the load for each class, regardless of location of the class. Table 5.2 presents load data for all the nonnetwork customer classes. Table 5.3 presents load data for all the network classes.

The two costing periods correspond with the data on prices of wholesale energy so that, later, the product of the load plus loss data and the price data are compatible with each other.

Table 5.4 presents an annual summary of loads for the areas just mentioned as well as for Seattle, Tukwila and the Other Suburbs. As mentioned, network residential and small loads are initially considered a part of the total network load. Ultimately, though, those loads are combined with their Seattle counterparts. Hence, there is a side-bar to Table 5.4 that indicates appropriate totals when the network residential and small customers are consolidated with their Seattle counterparts. Since the allocation of revenue requirements is for the sum of requirements for 2007 and 2008, the sum of their loads is presented on this table.

Table 5.5 presents shares of load by class and area. These shares are used to allocate the total nonnetwork load by class among Seattle, Tukwila and the Other Suburbs. The shares of the summed loads for 2007 and 2008 are used to allocate the summed revenue requirements for those two years.

Table 5.1
Service Territory Load, MWH, for 2007-2008 by Two Costing Periods/Month

		Total Service Territory						
		Total	Residential	Small	Medium	Large	High Demand	Lights
Jan	Mon-Sa HLH	558,021.20	224,063.11	69,762.85	129,251.59	80,762.24	49,878.41	4,303.00
Jan	Other hrs	348,249.80	145,822.89	41,316.15	71,087.41	47,584.76	36,480.59	5,958.00
2007	**Jan Total**	**906,271.00**	**369,886.00**	**111,079.00**	**200,339.00**	**128,347.00**	**86,359.00**	**10,261.00**
Feb	Mon-Sa HLH	504,341.96	188,776.16	64,848.82	120,090.46	76,910.92	50,240.01	3,475.60
Feb	Other hrs	296,551.04	114,695.84	34,849.18	62,101.54	42,060.08	37,630.99	5,213.40
2007	**Feb Total**	**800,893.00**	**303,472.00**	**99,698.00**	**182,192.00**	**118,971.00**	**87,871.00**	**8,689.00**
Mar	Mon-Sa HLH	543,741.30	199,728.52	69,660.74	134,574.72	80,362.94	56,614.64	2,799.74
Mar	Other hrs	299,885.70	112,084.48	35,455.26	65,987.28	42,347.06	38,474.36	5,537.26
2007	**Mar Total**	**843,627.00**	**311,813.00**	**105,116.00**	**200,562.00**	**122,710.00**	**95,089.00**	**8,337.00**
Apr	Mon-Sa HLH	476,412.61	156,189.14	61,976.27	124,150.62	78,028.49	54,516.50	1,551.59
Apr	Other hrs	297,228.39	103,640.86	34,773.73	66,896.38	44,865.51	41,776.50	5,275.41
2007	**Apr Total**	**773,641.00**	**259,830.00**	**96,750.00**	**191,047.00**	**122,894.00**	**96,293.00**	**6,827.00**
May	Mon-Sa HLH	461,672.20	134,811.92	62,289.50	126,685.07	79,295.72	57,514.26	1,075.73
May	Other hrs	278,527.80	87,153.08	33,707.50	65,919.93	44,100.28	42,309.74	5,337.27
2007	**May Total**	**740,200.00**	**221,965.00**	**95,997.00**	**192,605.00**	**123,396.00**	**99,824.00**	**6,413.00**
Jun	Mon-Sa HLH	451,776.68	122,976.02	61,646.80	125,845.54	81,871.08	58,899.32	537.91
Jun	Other hrs	250,006.32	70,596.98	30,503.20	61,464.46	42,099.92	40,293.68	5,048.09
2007	**Jun Total**	**701,783.00**	**193,573.00**	**92,150.00**	**187,310.00**	**123,971.00**	**99,193.00**	**5,586.00**
Jul	Mon-Sa HLH	439,430.18	114,067.46	61,655.14	125,832.59	82,113.99	55,243.79	517.20
Jul	Other hrs	287,777.82	79,649.54	35,111.86	72,481.41	49,331.01	45,949.21	5,254.80
2007	**Jul Total**	**727,208.00**	**193,717.00**	**96,767.00**	**198,314.00**	**131,445.00**	**101,193.00**	**5,772.00**
Aug	Mon-Sa HLH	483,219.05	129,213.62	66,105.78	135,060.33	89,004.50	62,717.71	1,117.10
Aug	Other hrs	261,239.95	72,650.38	31,724.22	66,178.67	45,230.50	40,160.29	5,295.90
2007	**Aug Total**	**744,459.00**	**201,864.00**	**97,830.00**	**201,239.00**	**134,235.00**	**102,878.00**	**6,413.00**
Sep	Mon-Sa HLH	423,162.42	115,079.62	58,294.67	119,614.15	75,916.67	52,271.19	1,986.13
Sep	Other hrs	282,961.58	77,462.38	35,433.33	71,303.85	48,116.33	45,183.81	5,461.87
2007	**Sep Total**	**706,124.00**	**192,542.00**	**93,728.00**	**190,918.00**	**124,033.00**	**97,455.00**	**7,448.00**
Oct	Mon-Sa HLH	509,416.19	159,340.09	66,788.52	134,765.80	85,105.46	60,065.08	3,351.24
Oct	Other hrs	276,794.81	87,337.91	33,222.48	64,911.20	44,276.54	41,419.92	5,626.76
2007	**Oct Total**	**786,211.00**	**246,678.00**	**100,011.00**	**199,677.00**	**129,382.00**	**101,485.00**	**8,978.00**
Nov	Mon-Sa HLH	526,366.51	193,250.35	66,066.72	129,183.07	78,992.64	54,744.83	4,128.90
Nov	Other hrs	320,258.49	119,500.65	37,146.28	71,100.93	46,908.36	39,801.17	5,801.10
2007	**Nov Total**	**846,625.00**	**312,751.00**	**103,213.00**	**200,284.00**	**125,901.00**	**94,546.00**	**9,930.00**
Dec	Mon-Sa HLH	548,639.00	216,454.14	68,396.28	128,100.31	81,666.91	49,883.86	4,137.50
Dec	Other hrs	370,543.00	147,911.86	42,268.72	78,807.69	53,752.09	41,679.14	6,123.50
2007	**Dec Total**	**919,182.00**	**364,366.00**	**110,665.00**	**206,908.00**	**135,419.00**	**91,563.00**	**10,261.00**
Jan	Mon-Sa HLH	567,684.60	228,196.18	71,016.26	131,634.12	82,078.00	50,457.03	4,303.00
Jan	Other hrs	354,194.40	148,512.82	42,058.74	72,399.88	48,354.00	36,910.97	5,958.00
2008	**Jan Total**	**921,879.00**	**376,709.00**	**113,075.00**	**204,034.00**	**130,432.00**	**87,368.00**	**10,261.00**
Feb	Mon-Sa HLH	533,866.25	199,989.14	68,752.28	127,333.70	81,383.02	52,912.55	3,495.57
Feb	Other hrs	308,959.75	119,593.86	36,378.72	64,834.30	43,831.98	39,127.45	5,193.43
2008	**Feb Total**	**842,826.00**	**319,583.00**	**105,131.00**	**192,168.00**	**125,215.00**	**92,040.00**	**8,689.00**
Mar	Mon-Sa HLH	534,478.73	195,933.29	68,699.10	132,933.18	79,089.69	55,127.43	2,696.04
Mar	Other hrs	323,663.27	121,778.71	38,342.90	71,302.82	45,596.31	41,001.57	5,640.96
2008	**Mar Total**	**858,142.00**	**317,712.00**	**107,042.00**	**204,236.00**	**124,686.00**	**96,129.00**	**8,337.00**
Apr	Mon-Sa HLH	502,436.17	165,932.30	65,245.04	130,463.35	81,930.20	57,251.63	1,613.65
Apr	Other hrs	284,465.83	98,888.70	33,295.96	64,073.65	42,934.80	40,059.37	5,213.35
2008	**Apr Total**	**786,902.00**	**264,821.00**	**98,541.00**	**194,537.00**	**124,865.00**	**97,311.00**	**6,827.00**
May	Mon-Sa HLH	468,701.35	137,571.04	63,253.65	128,427.49	80,276.25	58,097.19	1,075.73
May	Other hrs	284,117.65	88,726.96	34,535.35	67,683.51	45,088.75	42,745.81	5,337.27
2008	**May Total**	**752,819.00**	**226,298.00**	**97,789.00**	**196,111.00**	**125,365.00**	**100,843.00**	**6,413.00**
Jun	Mon-Sa HLH	444,296.09	120,310.98	60,934.32	124,589.51	80,765.49	57,178.57	517.22
Jun	Other hrs	269,424.91	77,117.02	32,952.68	66,120.49	45,175.51	42,990.43	5,068.78
2008	**Jun Total**	**713,721.00**	**197,428.00**	**93,887.00**	**190,710.00**	**125,941.00**	**100,169.00**	**5,586.00**
Jul	Mon-Sa HLH	462,926.20	121,070.27	64,900.75	132,266.88	86,190.14	57,960.27	537.89
Jul	Other hrs	276,430.80	76,435.73	33,677.25	69,599.12	47,305.86	44,178.73	5,234.11
2008	**Jul Total**	**739,357.00**	**197,506.00**	**98,578.00**	**201,866.00**	**133,496.00**	**102,139.00**	**5,772.00**
Aug	Mon-Sa HLH	473,628.63	126,548.29	64,994.76	132,702.42	87,240.77	61,066.67	1,075.73
Aug	Other hrs	282,787.37	79,049.71	34,622.24	72,049.58	49,019.23	42,709.33	5,337.27
2008	**Aug Total**	**756,416.00**	**205,598.00**	**99,617.00**	**204,752.00**	**136,260.00**	**103,776.00**	**6,413.00**
Sep	Mon-Sa HLH	447,068.84	122,044.51	61,659.13	126,429.44	80,074.98	54,791.89	2,068.89
Sep	Other hrs	269,911.16	73,836.49	33,735.87	67,739.56	45,766.02	43,454.11	5,379.11
2008	**Sep Total**	**716,980.00**	**195,881.00**	**95,395.00**	**194,169.00**	**125,841.00**	**98,246.00**	**7,448.00**
Oct	Mon-Sa HLH	517,041.62	161,925.86	67,947.07	137,001.65	86,314.49	60,501.31	3,351.24
Oct	Other hrs	280,803.38	88,755.14	33,798.93	65,988.35	44,889.51	41,744.69	5,626.76
2008	**Oct Total**	**797,845.00**	**250,681.00**	**101,746.00**	**202,990.00**	**131,204.00**	**102,246.00**	**8,978.00**
Nov	Mon-Sa HLH	513,410.90	188,307.29	64,671.00	126,359.82	77,017.33	53,091.71	3,963.74
Nov	Other hrs	345,288.10	129,181.71	40,283.00	77,159.18	50,591.67	42,106.29	5,966.26
2008	**Nov Total**	**858,699.00**	**317,489.00**	**104,954.00**	**203,519.00**	**127,609.00**	**95,198.00**	**9,930.00**
Dec	Mon-Sa HLH	577,870.29	228,596.52	72,092.66	134,943.32	85,900.88	52,033.91	4,303.00
Dec	Other hrs	353,924.71	140,973.48	40,387.34	75,214.68	51,286.12	40,105.09	5,958.00
2008	**Dec Total**	**931,795.00**	**369,570.00**	**112,480.00**	**210,158.00**	**137,187.00**	**92,139.00**	**10,261.00**

Table 5.2
Nonnetwork Load, MWH, for 2007-2008 by Two Costing Periods/Month

		Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)						
		Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Jan	Mon-Sa HLH	482,762.11	218,967.57	60,597.90	102,311.94	46,703.29	49,878.41	4,303.00
Jan	Other hrs	304,768.89	142,098.43	36,100.10	55,024.06	29,107.71	36,480.59	5,958.00
2007	**Jan Total**	**787,531.00**	**361,066.00**	**96,698.00**	**157,336.00**	**75,811.00**	**86,359.00**	**10,261.00**
Feb	Mon-Sa HLH	433,691.96	184,421.68	56,415.30	94,831.72	44,307.66	50,240.01	3,475.60
Feb	Other hrs	259,314.04	111,870.32	30,377.70	48,255.28	25,966.34	37,630.99	5,213.40
2007	**Feb Total**	**693,006.00**	**296,292.00**	**86,793.00**	**143,087.00**	**70,274.00**	**87,871.00**	**8,689.00**
Mar	Mon-Sa HLH	467,485.47	195,108.97	60,598.82	106,205.48	46,157.81	56,614.64	2,799.74
Mar	Other hrs	261,858.53	109,296.03	30,913.18	51,311.52	26,326.19	38,474.36	5,537.26
2007	**Mar Total**	**729,344.00**	**304,405.00**	**91,512.00**	**157,517.00**	**72,484.00**	**95,089.00**	**8,337.00**
Apr	Mon-Sa HLH	404,861.12	152,512.43	53,846.89	97,870.84	44,562.87	54,516.50	1,551.59
Apr	Other hrs	258,800.88	101,158.57	30,383.11	52,176.16	28,031.13	41,776.50	5,275.41
2007	**Apr Total**	**663,662.00**	**253,671.00**	**84,230.00**	**150,047.00**	**72,594.00**	**96,293.00**	**6,827.00**
May	Mon-Sa HLH	389,498.90	131,647.23	54,136.99	99,899.27	45,225.42	57,514.26	1,075.73
May	Other hrs	241,177.10	85,049.77	29,440.01	51,373.73	27,666.58	42,309.74	5,337.27
2007	**May Total**	**630,676.00**	**216,697.00**	**83,577.00**	**151,273.00**	**72,892.00**	**99,824.00**	**6,413.00**
Jun	Mon-Sa HLH	378,801.21	120,108.43	53,557.30	98,995.52	46,702.73	58,899.32	537.91
Jun	Other hrs	215,514.79	68,849.57	26,671.70	48,121.48	26,530.27	40,293.68	5,048.09
2007	**Jun Total**	**594,316.00**	**188,958.00**	**80,229.00**	**147,117.00**	**73,233.00**	**99,193.00**	**5,586.00**
Jul	Mon-Sa HLH	366,572.29	111,387.58	53,670.06	98,984.81	46,768.85	55,243.79	517.20
Jul	Other hrs	247,138.71	77,704.42	30,579.94	56,776.19	30,874.15	45,949.21	5,254.80
2007	**Jul Total**	**613,711.00**	**189,092.00**	**84,250.00**	**155,761.00**	**77,643.00**	**101,193.00**	**5,772.00**
Aug	Mon-Sa HLH	404,467.54	126,176.02	57,517.69	106,122.18	50,816.83	62,717.71	1,117.10
Aug	Other hrs	224,372.46	70,860.98	27,658.31	51,934.82	28,462.17	40,160.29	5,295.90
2007	**Aug Total**	**628,840.00**	**197,037.00**	**85,176.00**	**158,057.00**	**79,279.00**	**102,878.00**	**6,413.00**
Sep	Mon-Sa HLH	355,006.18	112,408.82	50,671.39	94,324.47	43,344.19	52,271.19	1,986.13
Sep	Other hrs	242,648.82	75,546.18	30,933.61	55,624.53	29,898.81	45,183.81	5,461.87
2007	**Sep Total**	**597,655.00**	**187,955.00**	**81,605.00**	**149,949.00**	**73,243.00**	**97,455.00**	**7,448.00**
Oct	Mon-Sa HLH	432,040.94	155,655.72	58,064.68	106,268.56	48,635.66	60,065.08	3,351.24
Oct	Other hrs	239,523.06	85,152.28	29,011.32	50,558.44	27,754.34	41,419.92	5,626.76
2007	**Oct Total**	**671,564.00**	**240,808.00**	**87,076.00**	**156,827.00**	**76,390.00**	**101,485.00**	**8,978.00**
Nov	Mon-Sa HLH	452,567.90	188,858.22	57,453.06	102,083.95	45,298.94	54,744.83	4,128.90
Nov	Other hrs	278,706.10	116,449.78	32,410.94	55,218.05	29,025.06	39,801.17	5,801.10
2007	**Nov Total**	**731,274.00**	**305,308.00**	**89,864.00**	**157,302.00**	**74,324.00**	**94,546.00**	**9,930.00**
Dec	Mon-Sa HLH	472,879.50	211,431.35	59,432.18	101,116.40	46,878.22	49,883.86	4,137.50
Dec	Other hrs	323,315.50	144,153.65	36,920.82	61,386.60	33,051.78	41,679.14	6,123.50
2007	**Dec Total**	**796,195.00**	**355,585.00**	**96,353.00**	**162,503.00**	**79,930.00**	**91,563.00**	**10,261.00**
Jan	Mon-Sa HLH	491,068.77	223,003.59	61,695.17	104,196.45	47,413.53	50,457.03	4,303.00
Jan	Other hrs	309,928.23	144,717.41	36,753.83	56,039.55	29,548.47	36,910.97	5,958.00
2008	**Jan Total**	**800,997.00**	**367,721.00**	**98,449.00**	**160,236.00**	**76,962.00**	**87,368.00**	**10,261.00**
Feb	Mon-Sa HLH	458,963.41	195,364.64	59,818.94	100,542.15	46,829.55	52,912.55	3,495.57
Feb	Other hrs	270,089.59	116,639.36	31,713.06	50,373.85	27,042.45	39,127.45	5,193.43
2008	**Feb Total**	**729,053.00**	**312,004.00**	**91,532.00**	**150,916.00**	**73,872.00**	**92,040.00**	**8,689.00**
Mar	Mon-Sa HLH	459,280.99	191,402.59	59,765.98	104,978.37	45,310.57	55,127.43	2,696.04
Mar	Other hrs	282,482.01	118,756.41	33,431.02	55,413.63	28,238.43	41,001.57	5,640.96
2008	**Mar Total**	**741,763.00**	**310,159.00**	**93,197.00**	**160,392.00**	**73,549.00**	**96,129.00**	**8,337.00**
Apr	Mon-Sa HLH	427,122.33	162,018.42	56,696.32	102,766.62	46,775.68	57,251.63	1,613.65
Apr	Other hrs	247,767.67	96,520.58	29,099.68	50,006.38	26,868.32	40,059.37	5,213.35
2008	**Apr Total**	**674,890.00**	**258,539.00**	**85,796.00**	**152,773.00**	**73,644.00**	**97,311.00**	**6,827.00**
May	Mon-Sa HLH	395,432.12	134,343.72	54,970.75	101,224.74	45,720.00	58,097.19	1,075.73
May	Other hrs	245,823.88	86,579.28	30,170.25	52,783.26	28,208.00	42,745.81	5,337.27
2008	**May Total**	**641,256.00**	**220,923.00**	**85,141.00**	**154,008.00**	**73,928.00**	**100,843.00**	**6,413.00**
Jun	Mon-Sa HLH	372,121.73	117,500.08	52,942.72	98,073.99	45,909.14	57,178.57	517.22
Jun	Other hrs	232,117.27	75,217.92	28,801.28	51,691.01	28,347.86	42,990.43	5,068.78
2008	**Jun Total**	**604,239.00**	**192,718.00**	**81,744.00**	**149,765.00**	**74,257.00**	**100,169.00**	**5,586.00**
Jul	Mon-Sa HLH	386,235.83	118,223.70	56,496.02	103,977.76	49,040.19	57,960.27	537.89
Jul	Other hrs	237,515.17	74,564.30	29,332.98	54,547.24	29,657.81	44,178.73	5,234.11
2008	**Jul Total**	**623,751.00**	**192,788.00**	**85,829.00**	**158,525.00**	**78,698.00**	**102,139.00**	**5,772.00**
Aug	Mon-Sa HLH	396,207.26	123,573.77	56,543.09	104,272.42	49,675.58	61,066.67	1,075.73
Aug	Other hrs	242,495.74	77,105.23	30,190.91	56,517.58	30,635.42	42,709.33	5,337.27
2008	**Aug Total**	**638,703.00**	**200,679.00**	**86,734.00**	**160,790.00**	**80,311.00**	**103,776.00**	**6,413.00**
Sep	Mon-Sa HLH	374,972.01	119,208.16	53,604.05	99,659.48	45,639.54	54,791.89	2,068.89
Sep	Other hrs	231,626.99	72,003.84	29,453.95	52,819.52	28,516.46	43,454.11	5,379.11
2008	**Sep Total**	**606,599.00**	**191,212.00**	**83,058.00**	**152,479.00**	**74,156.00**	**98,246.00**	**7,448.00**
Oct	Mon-Sa HLH	438,338.68	158,179.98	59,072.84	108,015.60	49,217.72	60,501.31	3,351.24
Oct	Other hrs	242,892.32	86,533.02	29,515.16	51,389.40	28,083.28	41,744.69	5,626.76
2008	**Oct Total**	**681,231.00**	**244,713.00**	**88,588.00**	**159,405.00**	**77,301.00**	**102,246.00**	**8,978.00**
Nov	Mon-Sa HLH	441,232.03	184,032.66	56,235.37	99,872.54	44,036.00	53,091.71	3,963.74
Nov	Other hrs	300,194.97	125,896.34	35,146.63	59,947.46	31,132.00	42,106.29	5,966.26
2008	**Nov Total**	**741,427.00**	**309,929.00**	**91,382.00**	**159,820.00**	**75,168.00**	**95,198.00**	**9,930.00**
Dec	Mon-Sa HLH	497,964.95	223,291.53	62,650.77	106,462.21	49,223.54	52,033.91	4,303.00
Dec	Other hrs	308,858.05	137,369.47	35,284.23	58,569.79	31,571.46	40,105.09	5,958.00
2008	**Dec Total**	**806,823.00**	**360,661.00**	**97,935.00**	**165,032.00**	**80,795.00**	**92,139.00**	**10,261.00**

Table 5.3
Network Load, MWH, for 2007-2008 by Two Costing Periods/Month

		Downtown Network				
		Total	Residential	Small	Medium	Large
Jan	Mon-Sa HLH	75,259.09	5,095.53	9,164.96	26,939.64	34,058.96
Jan	Other hrs	43,480.91	3,724.47	5,216.04	16,063.36	18,477.04
2007	**Jan Total**	**118,740.00**	**8,820.00**	**14,381.00**	**43,003.00**	**52,536.00**
Feb	Mon-Sa HLH	70,649.99	4,354.48	8,433.52	25,258.74	32,603.26
Feb	Other hrs	37,237.01	2,825.52	4,471.48	13,846.26	16,093.74
2007	**Feb Total**	**107,887.00**	**7,180.00**	**12,905.00**	**39,105.00**	**48,697.00**
Mar	Mon-Sa HLH	76,255.83	4,619.55	9,061.92	28,369.23	34,205.13
Mar	Other hrs	38,027.17	2,788.45	4,542.08	14,675.77	16,020.87
2007	**Mar Total**	**114,283.00**	**7,408.00**	**13,604.00**	**43,045.00**	**50,226.00**
Apr	Mon-Sa HLH	71,551.49	3,676.71	8,129.38	26,279.78	33,465.63
Apr	Other hrs	38,427.51	2,482.29	4,390.62	14,720.22	16,834.37
2007	**Apr Total**	**109,979.00**	**6,159.00**	**12,520.00**	**41,000.00**	**50,300.00**
May	Mon-Sa HLH	72,173.30	3,164.69	8,152.51	26,785.80	34,070.30
May	Other hrs	37,350.70	2,103.31	4,267.49	14,546.20	16,433.70
2007	**May Total**	**109,524.00**	**5,268.00**	**12,420.00**	**41,332.00**	**50,504.00**
Jun	Mon-Sa HLH	72,975.47	2,867.60	8,089.50	26,850.02	35,168.35
Jun	Other hrs	34,491.53	1,747.40	3,831.50	13,342.98	15,569.65
2007	**Jun Total**	**107,467.00**	**4,615.00**	**11,921.00**	**40,193.00**	**50,738.00**
Jul	Mon-Sa HLH	72,857.89	2,679.88	7,985.08	26,847.78	35,345.15
Jul	Other hrs	40,639.11	1,945.12	4,531.92	15,705.22	18,456.85
2007	**Jul Total**	**113,497.00**	**4,625.00**	**12,517.00**	**42,553.00**	**53,802.00**
Aug	Mon-Sa HLH	78,751.51	3,037.60	8,588.09	28,938.15	38,187.67
Aug	Other hrs	36,867.49	1,789.40	4,065.91	14,243.85	16,768.33
2007	**Aug Total**	**115,619.00**	**4,827.00**	**12,654.00**	**43,182.00**	**54,956.00**
Sep	Mon-Sa HLH	68,156.24	2,670.80	7,623.28	25,289.69	32,572.48
Sep	Other hrs	40,312.76	1,916.20	4,499.72	15,679.31	18,217.52
2007	**Sep Total**	**108,469.00**	**4,587.00**	**12,123.00**	**40,969.00**	**50,790.00**
Oct	Mon-Sa HLH	77,375.25	3,684.37	8,723.83	28,497.24	36,469.81
Oct	Other hrs	37,271.75	2,185.63	4,211.17	14,352.76	16,522.19
2007	**Oct Total**	**114,647.00**	**5,870.00**	**12,935.00**	**42,850.00**	**52,992.00**
Nov	Mon-Sa HLH	73,798.61	4,392.13	8,613.66	27,099.12	33,693.70
Nov	Other hrs	41,552.39	3,050.87	4,735.34	15,882.88	17,883.30
2007	**Nov Total**	**115,351.00**	**7,443.00**	**13,349.00**	**42,982.00**	**51,577.00**
Dec	Mon-Sa HLH	75,759.50	5,022.79	8,964.10	26,983.92	34,788.69
Dec	Other hrs	47,227.50	3,758.21	5,347.90	17,421.08	20,700.31
2007	**Dec Total**	**122,987.00**	**8,781.00**	**14,312.00**	**44,405.00**	**55,489.00**
Jan	Mon-Sa HLH	76,615.83	5,192.59	9,321.09	27,437.68	34,664.47
Jan	Other hrs	44,266.17	3,795.41	5,304.91	16,360.32	18,805.53
2008	**Jan Total**	**120,882.00**	**8,988.00**	**14,626.00**	**43,798.00**	**53,470.00**
Feb	Mon-Sa HLH	74,902.83	4,624.49	8,933.33	26,791.54	34,553.46
Feb	Other hrs	38,870.17	2,954.51	4,665.67	14,460.46	16,789.54
2008	**Feb Total**	**113,773.00**	**7,579.00**	**13,599.00**	**41,252.00**	**51,343.00**
Mar	Mon-Sa HLH	75,197.74	4,530.69	8,933.12	27,954.80	33,779.12
Mar	Other hrs	41,181.26	3,022.31	4,911.88	15,889.20	17,357.88
2008	**Mar Total**	**116,379.00**	**7,553.00**	**13,845.00**	**43,844.00**	**51,137.00**
Apr	Mon-Sa HLH	75,313.85	3,913.88	8,548.72	27,696.73	35,154.52
Apr	Other hrs	36,698.15	2,368.12	4,196.28	14,067.27	16,066.48
2008	**Apr Total**	**112,012.00**	**6,282.00**	**12,745.00**	**41,764.00**	**51,221.00**
May	Mon-Sa HLH	73,269.23	3,227.32	8,282.90	27,202.75	34,556.26
May	Other hrs	38,293.77	2,147.68	4,365.10	14,900.25	16,880.74
2008	**May Total**	**111,563.00**	**5,375.00**	**12,648.00**	**42,103.00**	**51,437.00**
Jun	Mon-Sa HLH	72,174.36	2,810.90	7,991.59	26,515.52	34,856.34
Jun	Other hrs	37,307.64	1,899.10	4,151.41	14,429.48	16,827.66
2008	**Jun Total**	**109,482.00**	**4,710.00**	**12,143.00**	**40,945.00**	**51,684.00**
Jul	Mon-Sa HLH	76,690.38	2,846.58	8,404.73	28,289.12	37,149.95
Jul	Other hrs	38,915.62	1,871.42	4,344.27	15,051.88	17,648.05
2008	**Jul Total**	**115,606.00**	**4,718.00**	**12,749.00**	**43,341.00**	**54,798.00**
Aug	Mon-Sa HLH	77,421.37	2,974.51	8,451.67	28,430.00	37,565.19
Aug	Other hrs	40,291.63	1,944.49	4,431.33	15,532.00	18,383.81
2008	**Aug Total**	**117,713.00**	**4,919.00**	**12,883.00**	**43,962.00**	**55,949.00**
Sep	Mon-Sa HLH	72,096.84	2,836.35	8,055.08	26,769.96	34,435.44
Sep	Other hrs	38,284.16	1,832.65	4,281.92	14,920.04	17,249.56
2008	**Sep Total**	**110,381.00**	**4,669.00**	**12,337.00**	**41,690.00**	**51,685.00**
Oct	Mon-Sa HLH	78,702.94	3,745.88	8,874.23	28,986.05	37,096.77
Oct	Other hrs	37,911.06	2,222.12	4,283.77	14,598.95	16,806.23
2008	**Oct Total**	**116,614.00**	**5,968.00**	**13,158.00**	**43,585.00**	**53,903.00**
Nov	Mon-Sa HLH	72,178.87	4,274.63	8,435.63	26,487.28	32,981.33
Nov	Other hrs	45,093.13	3,285.37	5,136.37	17,211.72	19,459.67
2008	**Nov Total**	**117,272.00**	**7,560.00**	**13,572.00**	**43,699.00**	**52,441.00**
Dec	Mon-Sa HLH	79,905.33	5,304.99	9,441.88	28,481.11	36,677.34
Dec	Other hrs	45,066.67	3,604.01	5,103.12	16,644.89	19,714.66
2008	**Dec Total**	**124,972.00**	**8,909.00**	**14,545.00**	**45,126.00**	**56,392.00**

Table 5.4
Annual Summary MWH Load Data

		Total	Residential	Small	Medium	Large	High Demand	Lights	Total	Residential	Small
Service Territory											
Actual	**2005**	9,118,267	2,960,662	1,176,231	2,267,669	1,549,018	1,069,832	94,855			
Forecast	**2006**	9,324,655	3,118,338	1,180,814	2,302,983	1,492,548	1,135,057	94,915			
	2007	9,496,224	3,172,457	1,203,004	2,351,395	1,520,704	1,153,749	94,915			
	2008	9,677,381	3,239,276	1,228,235	2,399,250	1,548,101	1,167,604	94,915			
	Sum of 2007 & 2008										
		19,173,605	6,411,733	2,431,239	4,750,645	3,068,805	2,321,353	189,830			
Total Nonnetwork (Excludes Network Residential & Small)									**Includes Ntwk Res & Small**		
Actual	**2005**	7,793,960	2,892,983	1,022,558	1,780,111	933,621	1,069,832	94,855	8,015,312	2,960,662	1,176,231
Forecast	**2006**	7,991,428	3,044,089	1,027,766	1,808,338	881,263	1,135,057	94,915	8,218,725	3,118,338	1,180,814
	2007	8,137,774	3,096,874	1,047,363	1,846,776	898,097	1,153,749	94,915	8,368,998	3,172,457	1,203,004
	2008	8,290,732	3,162,046	1,069,385	1,884,141	912,641	1,167,604	94,915	8,526,812	3,239,276	1,228,235
	Sum of 2007 & 2008										
		16,428,506	6,258,920	2,116,748	3,730,917	1,810,738	2,321,353	189,830	16,895,810	6,411,733	2,431,239
Downtown Network (Includes Network Residential & Small)									**Excludes Ntwk Res & Small**		
Actual	**2005**	1,324,307	67,679	153,673	487,558	615,397			1,102,955		
Forecast	**2006**	1,333,227	74,249	153,048	494,645	611,285			1,105,930		
	2007	1,358,450	75,583	155,641	504,619	622,607			1,127,226		
	2008	1,386,649	77,230	158,850	515,109	635,460			1,150,569		
	Sum of 2007 & 2008										
		2,745,099	152,813	314,491	1,019,728	1,258,067			2,277,795		
City of Seattle Nonnetwork (Excludes Network Residential & Small)									**Includes Ntwk Res & Small**		
Actual	**2005**	6,340,580	2,234,954	851,451	1,494,932	714,568	949,820	94,855	6,561,932	2,302,633	1,005,124
Forecast	**2006**	6,507,978	2,346,715	858,026	1,526,347	749,252	932,723	94,915	6,735,275	2,420,964	1,011,074
	2007	6,626,235	2,387,505	874,307	1,558,064	763,414	948,030	94,915	6,857,459	2,463,088	1,029,948
	2008	6,751,812	2,437,868	892,648	1,589,438	776,223	960,720	94,915	6,987,892	2,515,098	1,051,498
	Sum of 2007 & 2008										
		13,378,047	4,825,373	1,766,955	3,147,502	1,539,637	1,908,750	189,830	13,845,351	4,978,186	2,081,446
Tukwila											
Actual	**2005**	488,722	52,060	31,249	89,728	195,673	120,012				
Forecast	**2006**	488,775	56,723	31,028	89,041	109,649	202,334				
	2007	497,652	57,680	31,640	90,993	111,620	205,719				
	2008	503,564	58,863	32,323	92,634	112,860	206,884				
	Sum of 2007 & 2008										
		1,001,216	116,543	63,963	183,627	224,480	412,603				
Other Suburbs											
Actual	**2005**	964,658	605,969	139,858	195,451	23,380					
Forecast	**2006**	994,675	640,651	138,712	192,950	22,362					
	2007	1,013,887	651,689	141,416	197,719	23,063					
	2008	1,035,356	665,315	144,414	202,069	23,558					
	Sum of 2007 & 2008										
		2,049,243	1,317,004	285,830	399,788	46,621					

Table 5.5
Annual Share of Load

		Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory								
Actual	**2005**	100.000%	32.470%	12.900%	24.870%	16.988%	11.733%	1.040%
Forecast	**2006**	100.000%	33.442%	12.663%	24.698%	16.006%	12.173%	1.018%
	2007	100.000%	33.408%	12.668%	24.761%	16.014%	12.150%	1.000%
	2008	100.000%	33.473%	12.692%	24.792%	15.997%	12.065%	0.981%
	2007+08	100.000%	33.440%	12.680%	24.777%	16.005%	12.107%	0.990%
Total Nonnetwork (Excludes Network Residential & Small)								
Actual	**2005**	100.000%	37.118%	13.120%	22.840%	11.979%	13.726%	1.217%
Forecast	**2006**	100.000%	38.092%	12.861%	22.628%	11.028%	14.203%	1.188%
	2007	100.000%	38.056%	12.870%	22.694%	11.036%	14.178%	1.166%
	2008	100.000%	38.140%	12.899%	22.726%	11.008%	14.083%	1.145%
	2007+08	100.000%	38.098%	12.885%	22.710%	11.022%	14.130%	1.155%
Downtown Network (Includes Network Residential & Small)								
Actual	**2005**	100.000%	5.111%	11.604%	36.816%	46.469%		
Forecast	**2006**	100.000%	5.569%	11.480%	37.101%	45.850%		
	2007	100.000%	5.564%	11.457%	37.147%	45.832%		
	2008	100.000%	5.570%	11.456%	37.148%	45.827%		
	2007+08	100.000%	5.567%	11.456%	37.147%	45.830%		
City of Seattle Nonnetwork (Excludes Network Residential & Small) as Percent of Total Nonnetwork by Class								
Actual	**2005**	81.352%	77.254%	83.267%	83.980%	76.537%	88.782%	100.000%
Forecast	**2006**	81.437%	77.091%	83.485%	84.406%	85.020%	82.174%	100.000%
	2007	81.426%	77.094%	83.477%	84.367%	85.004%	82.170%	100.000%
	2008	81.438%	77.098%	83.473%	84.359%	85.052%	82.281%	100.000%
	2007+08	81.432%	77.096%	83.475%	84.363%	85.028%	82.226%	100.000%
Tukwila as Percent of Total Nonnetwork by Class								
Actual	**2005**	6.271%	1.800%	3.056%	5.041%	20.959%	11.218%	
Forecast	**2006**	6.116%	1.863%	3.019%	4.924%	12.442%	17.826%	
	2007	6.115%	1.863%	3.021%	4.927%	12.429%	17.830%	
	2008	6.074%	1.862%	3.023%	4.917%	12.366%	17.719%	
	2007+08	6.094%	1.862%	3.022%	4.922%	12.397%	17.774%	
Other Suburbs as Percent of Total Nonnetwork by Class								
Actual	**2005**	12.377%	20.946%	13.677%	10.980%	2.504%		
Forecast	**2006**	12.447%	21.046%	13.496%	10.670%	2.537%		
	2007	12.459%	21.043%	13.502%	10.706%	2.568%		
	2008	12.488%	21.041%	13.504%	10.725%	2.581%		
	2007+08	12.474%	21.042%	13.503%	10.716%	2.575%		
Total Nonnetwork (Excludes Network Residential & Small) as Percent of Total Service Territory								
Actual	**2005**	85.476%	31.727%	11.214%	19.522%	10.239%	11.733%	1.040%
Forecast	**2006**	85.702%	32.646%	11.022%	19.393%	9.451%	12.173%	1.018%
	2007	85.695%	32.612%	11.029%	19.447%	9.457%	12.150%	1.000%
	2008	85.671%	32.675%	11.050%	19.470%	9.431%	12.065%	0.981%
	2007+08	85.683%	32.643%	11.040%	19.459%	9.444%	12.107%	0.990%
Downtown Network (Includes Network Residential & Small) as Percent of Total Service Territory								
Actual	**2005**	14.524%	0.742%	1.685%	5.347%	6.749%		
Forecast	**2006**	14.298%	0.796%	1.641%	5.305%	6.556%		
	2007	14.305%	0.796%	1.639%	5.314%	6.556%		
	2008	14.329%	0.798%	1.641%	5.323%	6.566%		
	2007+08	14.317%	0.797%	1.640%	5.318%	6.561%		

5.2 Peak Load Data

The marginal cost by class for several distribution revenue requirements is estimated by summing over the classes appropriate estimates of $/MW multiplied by load (in MW) during the coincident peak period. In this chapter we need to focus on the development of the coincident peak MW for each class.

Peak loads by class: Hourly consumption data are collected for a sample of customers in the residential, small and medium classes. Hourly consumption data are collected for all large and high demand customers. The sample data are inflated to estimate the hourly consumption for the total class (each hour's consumption is converted to a percentage of the sample's total consumption in the year and then multiplied by the class's total annual energy billed). Since there is potential for measurement error in the sample and since the sample may not be totally representative at all times of the total class, there is always a question of how reliable are the estimates for totals of those classes whose data are only sampled. Even for the classes with complete samples, there is always a question whether weather or idiosyncratic economic factors contribute to specific hours of peak loads. Hence, for the last several rate cases, estimates of projected consumption for aggregations of the hourly data were used (4 costing periods each month) with the expectation that statistical errors in individual hours would, on average, balance out in the forecast periods. The total energy estimated for each period is then divided by the expected number of hours in the period to estimate the average hourly consumption. The peak period by class and coincident peak periods for nonnetwork and network classes as total groups are then determined by the costing period with the largest hourly average consumption.

Table 5.6 presents annual MW data for the total service territory, nonnetwork and network areas. Data are presented for the annual average load by customer class, as well as the average MW per hour in the costing period with the maximum load for the years 2005 through 2008. Additionally, since much of the distribution system is sized to meet the coincident peak load for nonnetwork and network areas, the load at the time of the peak for each of those two areas is presented. These latter peak loads are used in determining costs for several of the distribution functions.

Figures 5.1 through 5.13 present for 2007, which is representative of the two years, the average MW per hour for each of the four costing periods each month, as well as the monthly average. These data are presented for the total nonnetwork and total network as well as for each class within those two areas. Figure 5.13 presents a summary of the load profile for the entire service territory.

Table 5.6

Average Annual MW and And Peak Load by Costing Period

		Total Service Territory						
		Total	Residential	Small	Medium	Large	High Demand	Lights
Average	2005	1,046.99	347.08	132.69	257.70	173.76	124.93	10.83
Annual	2006	1,064.46	355.97	134.80	262.90	170.38	129.57	10.84
Load,	2007	1,084.04	362.15	137.33	268.42	173.60	131.71	10.84
MW	2008	1,101.71	368.77	139.83	273.14	176.24	132.92	10.81
Peak	2005	1,337.26	554.07	170.88	328.47	215.26	149.42	20.73
Load, MW	2006	1,375.54	602.15	173.65	331.65	209.81	148.16	20.75
during	2007	1,399.17	621.34	177.34	338.30	213.53	149.57	20.74
year	2008	1,410.25	632.80	178.21	349.74	219.75	151.86	20.74
Period	2005	Dec WD HLH	Jan SU HLH	Feb WD HLH	Dec WD HLH	Jul WD HLH	Sep SA HLH	Apr HLH
of	2006	Dec WD HLH	Jan SU HLH	Dec WD HLH	Nov WD HLH	Jul WD HLH	Sep SA HLH	Apr HLH
Peak	2007	Dec WD HLH	Jan SU HLH	Dec WD HLH	Nov WD HLH	Aug WD HLH	Sep SA HLH	Mar HLH
Load	2008	Dec WD HLH	Jan SU HLH	Dec WD HLH	Nov WD HLH	Aug WD HLH	Sep SA HLH	Mar HLH

		Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)						
		Total	Residential	Small	Medium	Large	High Demand	Lights
Average	2005	898.85	339.06	115.64	204.17	104.23	124.93	10.83
Annual	2006	912.26	347.50	117.32	206.43	100.60	129.57	10.84
Load,	2007	928.97	353.52	119.56	210.82	102.52	131.71	10.84
MW	2008	943.84	359.98	121.74	214.50	103.90	132.92	10.81
Peak	2005	1,153.51	542.35	149.05	262.49	123.66	149.42	20.73
Load, MW	2006	1,182.12	589.01	151.06	263.25	118.50	148.16	20.75
during	2007	1,201.76	607.61	154.28	268.57	121.30	149.57	20.74
year	2008	1,211.99	618.81	155.30	278.11	123.91	151.86	20.74
Period	2005	Dec WD HLH	Jan SU HLH	Feb WD HLH	Dec WD HLH	Jul WD HLH	Sep SA HLH	Apr HLH
of	2006	Dec WD HLH	Jan SU HLH	Dec WD HLH	Nov WD HLH	Feb WD HLH	Sep SA HLH	Apr HLH
Peak	2007	Dec WD HLH	Jan SU HLH	Dec WD HLH	Nov WD HLH	Dec WD HLH	Sep SA HLH	Mar HLH
Load	2008	Dec WD HLH	Jan SU HLH	Feb WD HLH	Nov WD HLH	Aug WD HLH	Sep SA HLH	Mar HLH
Load at	2005	1,153.51	502.42	143.16	262.49	117.77	117.33	10.34
time of	2006	1,182.12	520.54	151.06	261.44	118.39	120.35	10.34
Coincident	2007	1,201.76	527.69	154.28	266.99	121.30	121.16	10.34
Peak	2008	1,211.99	536.06	155.00	266.83	121.49	122.26	10.34

		Downtown Network				
		Total	Residential	Small	Medium	Large
Average	2005	148.13	8.02	17.04	53.53	69.54
Annual	2006	152.19	8.48	17.47	56.47	69.78
Load,	2007	155.07	8.63	17.77	57.60	71.07
MW	2008	157.86	8.79	18.08	58.64	72.34
Peak	2005	183.74	12.30	22.00	65.98	91.60
Load, MW	2006	193.42	13.14	22.59	68.52	91.39
during	2007	197.41	13.73	23.07	69.93	92.61
year	2008	198.26	14.00	23.20	71.63	95.84
Period	2005	Dec WD HLH	Dec SU HLH	Jan WD HLH	Dec WD HLH	Jul WD HLH
of	2006	Dec WD HLH	Jan SU HLH	Dec WD HLH	Dec WD HLH	Jul WD HLH
Peak	2007	Dec WD HLH	Jan SU HLH	Dec WD HLH	Dec WD HLH	Jul WD HLH
Load	2008	Dec WD HLH	Jan SU HLH	Dec WD HLH	Nov WD HLH	Aug WD HLH
Load at	2005	183.74	11.62	21.17	65.98	84.97
time of	2006	193.42	12.42	22.59	68.52	89.89
Coincident	2007	197.41	12.52	23.07	69.93	91.89
Peak	2008	198.26	12.72	23.20	70.38	91.96

Figure 5.1

Total, Nonnetwork
Usage Per Hour By Costing Period

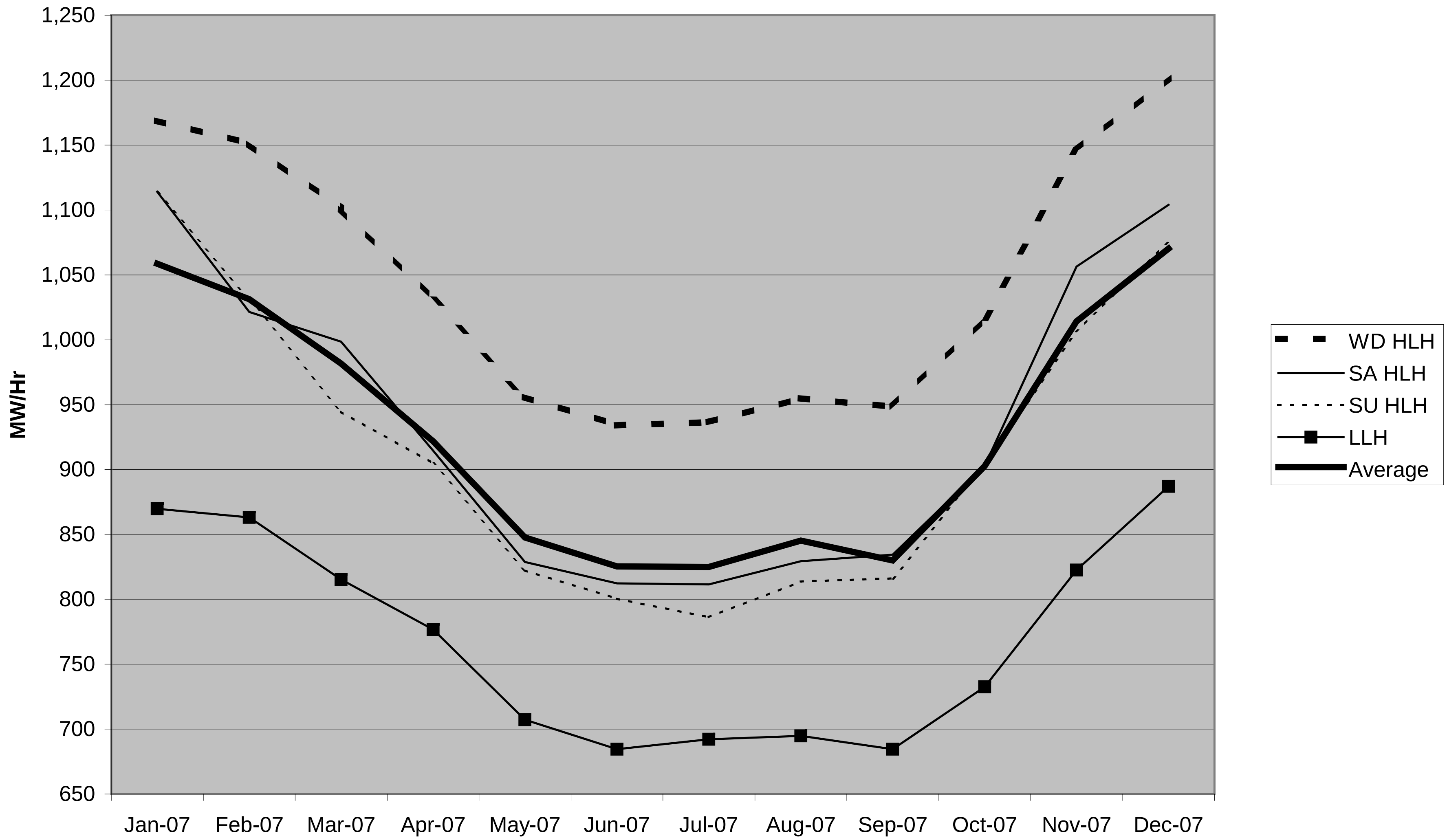


Figure 5.2

Residential, Nonnetwork
Usage Per Hour By Costing Period

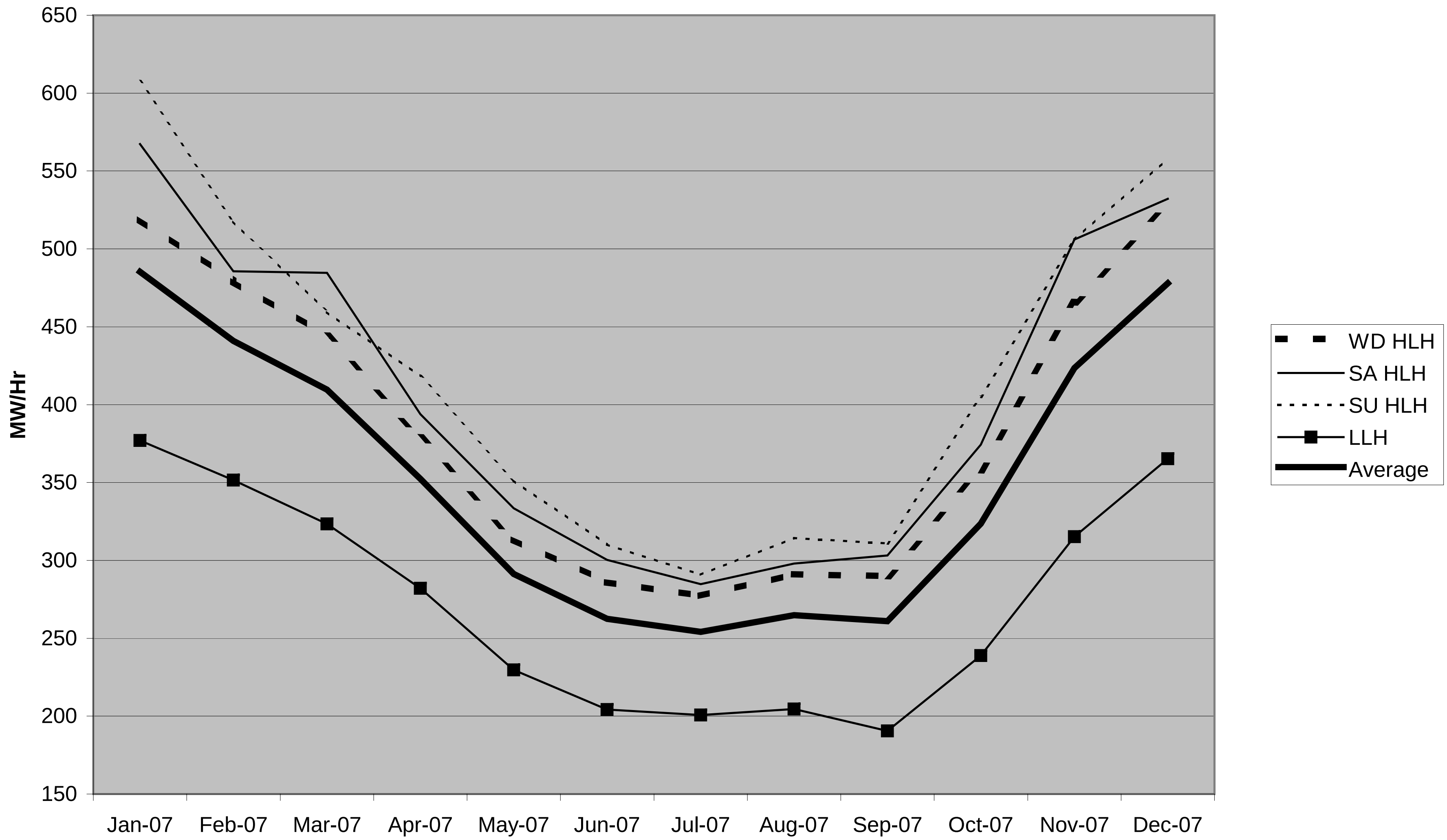


Figure 5.3

Small, Nonnetwork
Usage Per Hour By Costing Period

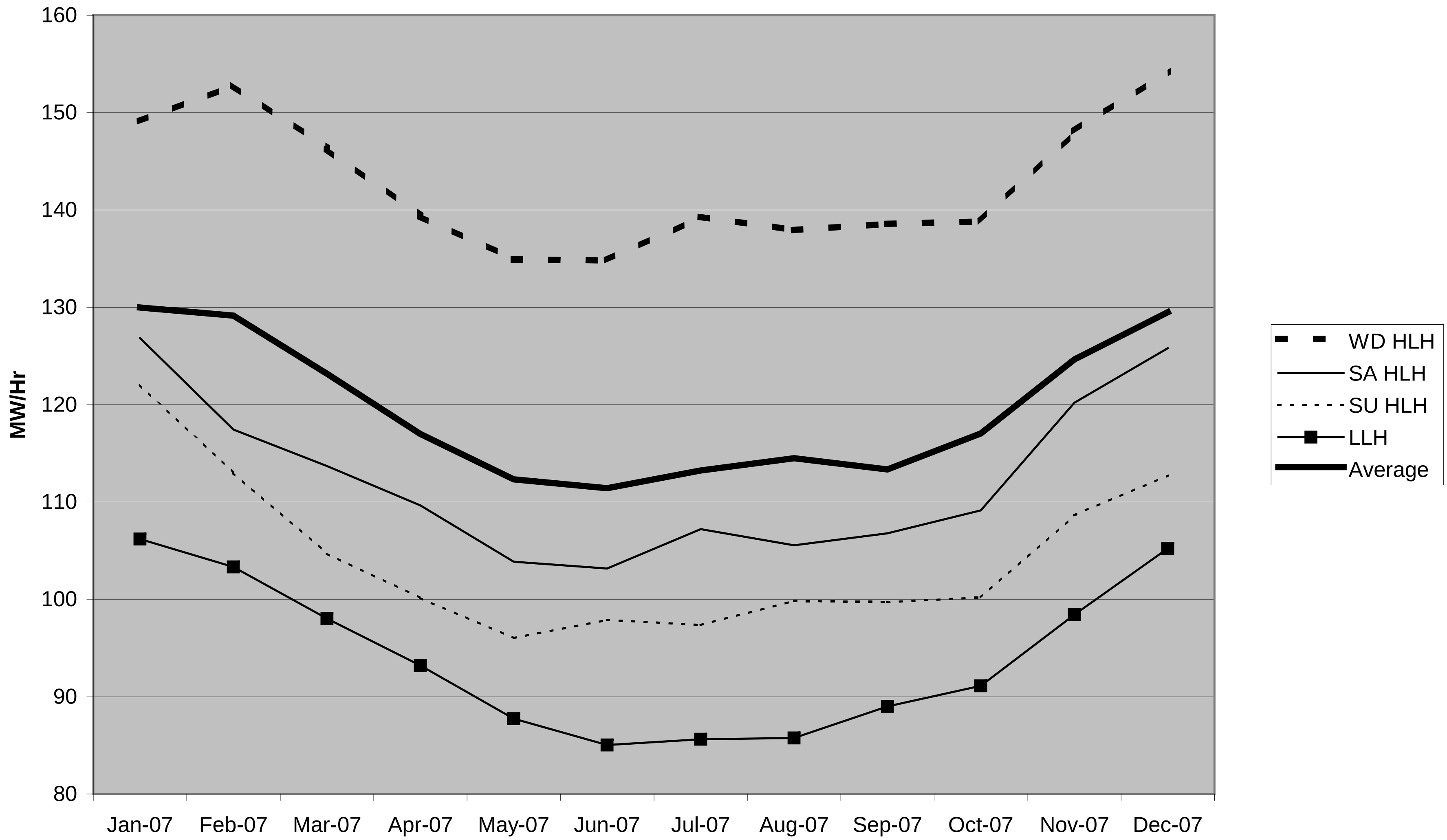


Figure 5.4

Medium, Nonnetwork
Usage Per Hour By Costing Period

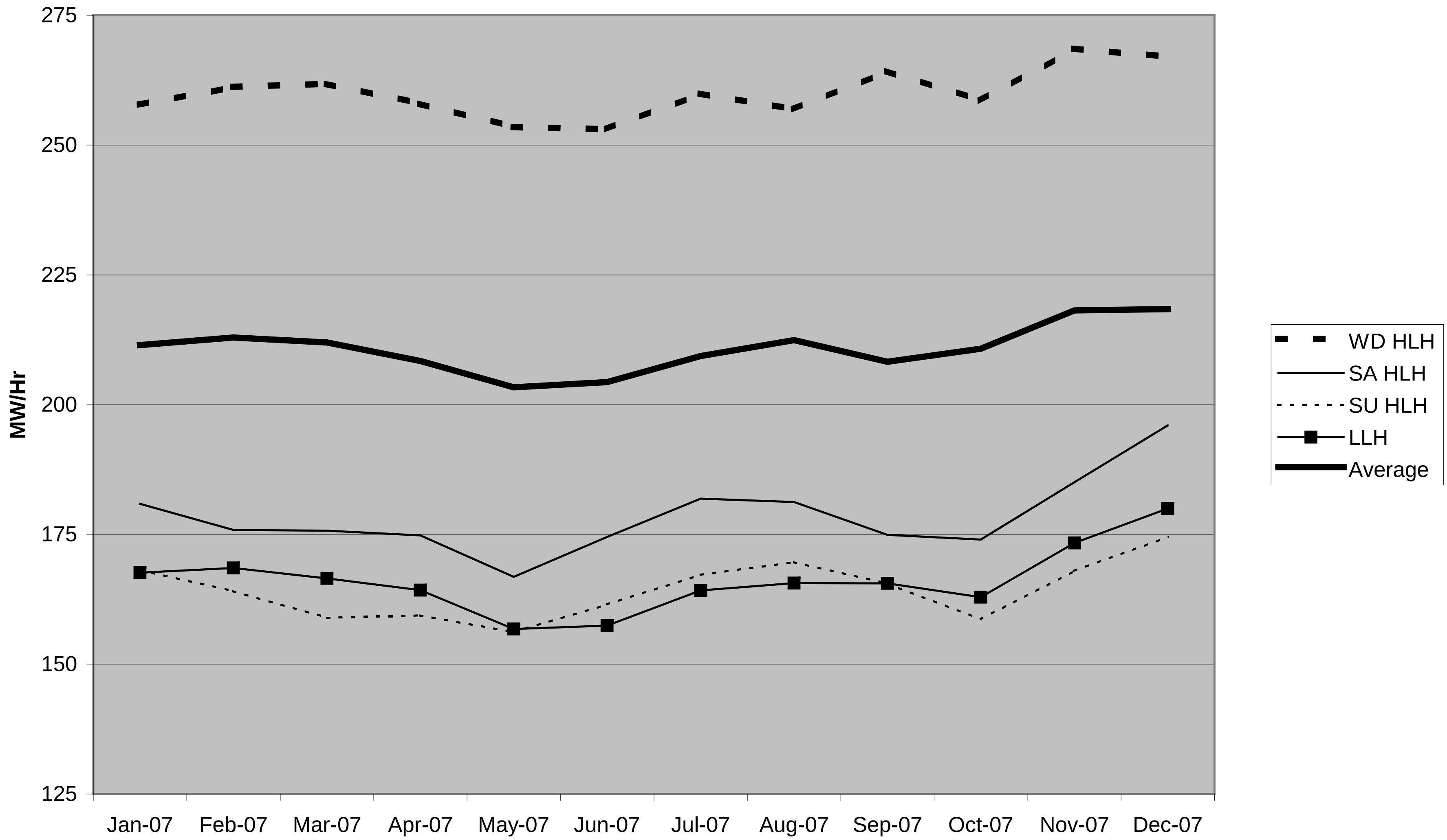


Figure 5.5

Large, Nonnetwork
Usage Per Hour By Costing Period

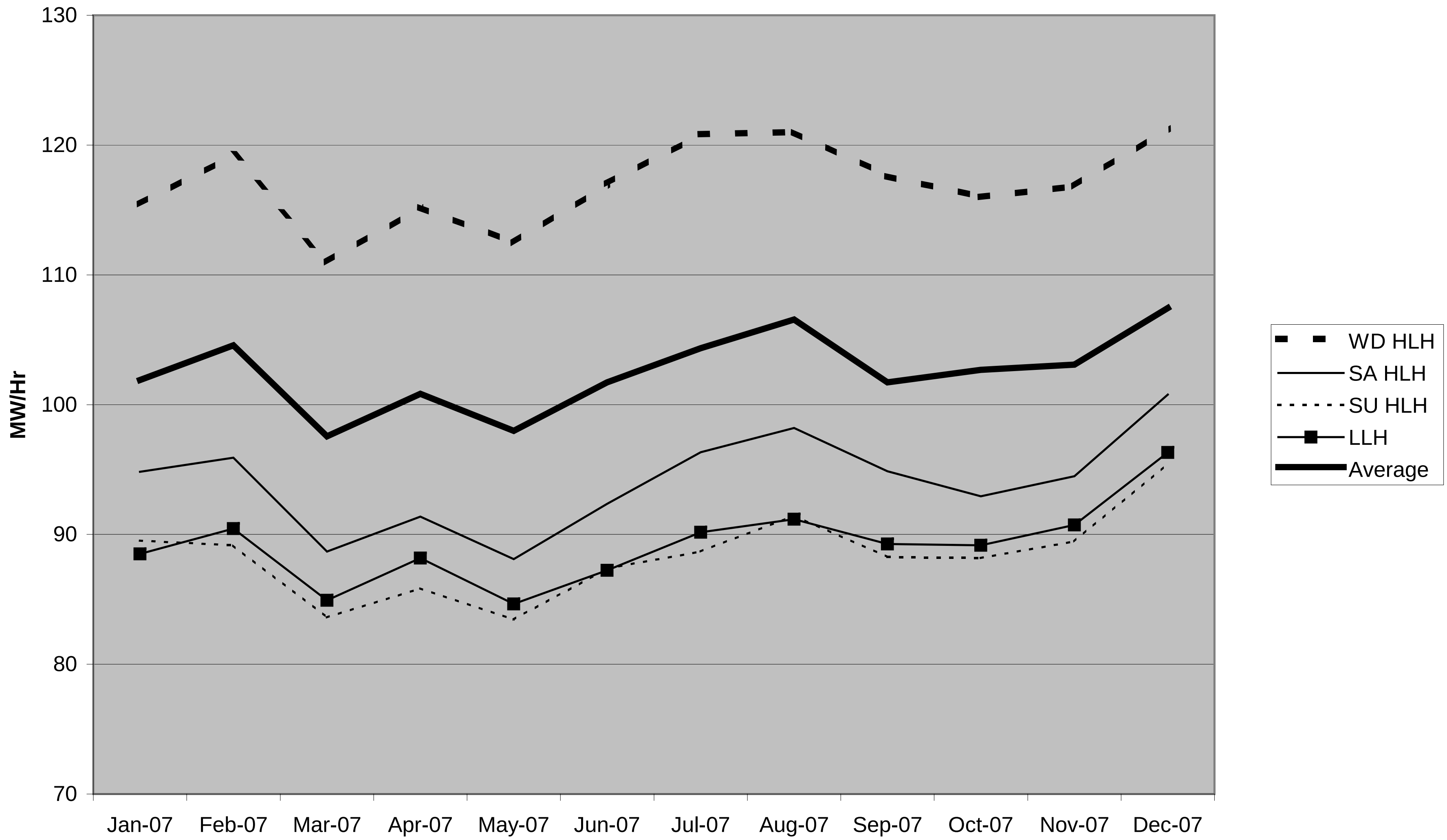


Figure 5.6

High Demand, Nonnetwork
Usage Per Hour By Costing Period

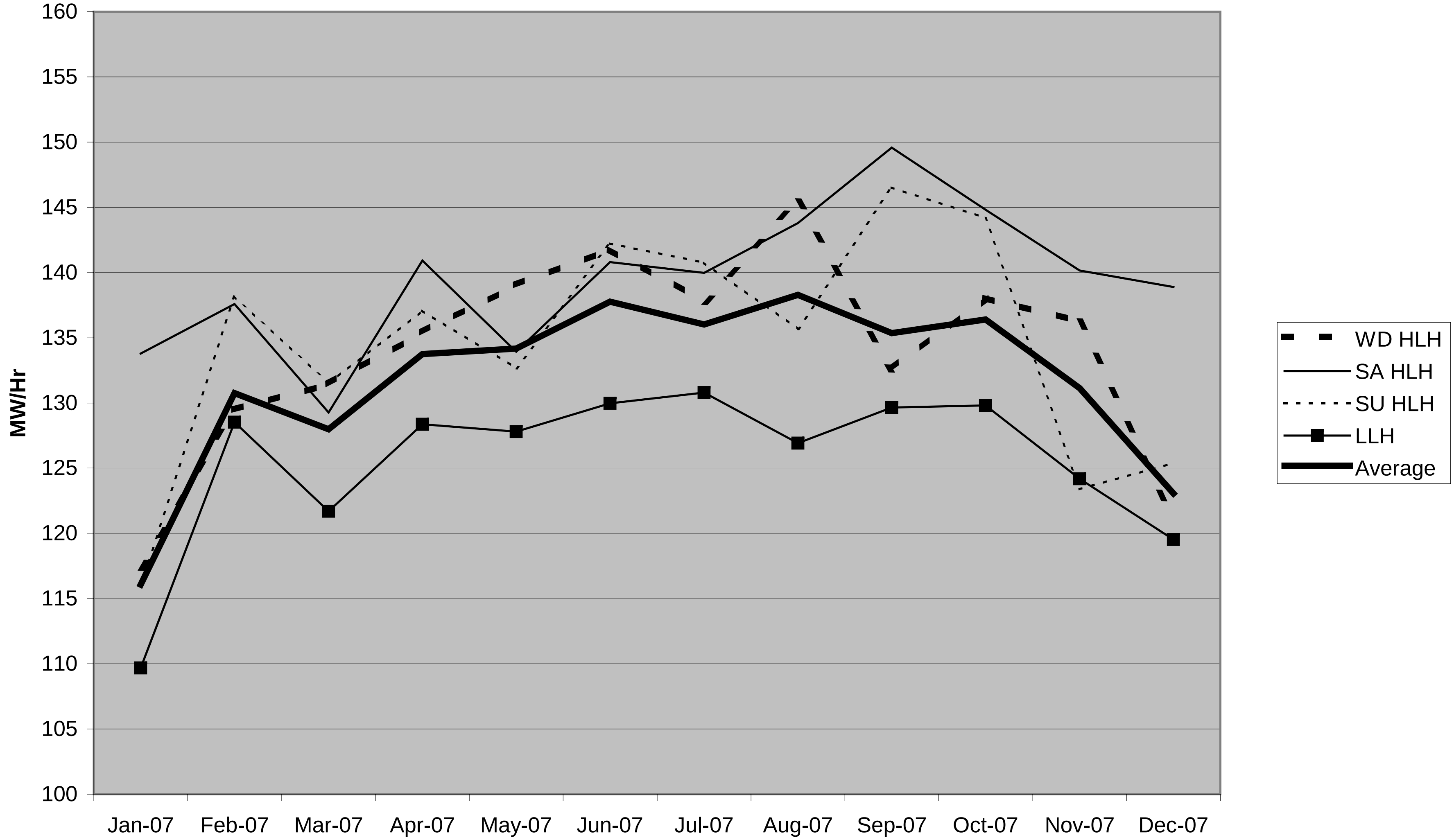


Figure 5.7

Lights, Nonnetwork
Usage Per Hour By Costing Period

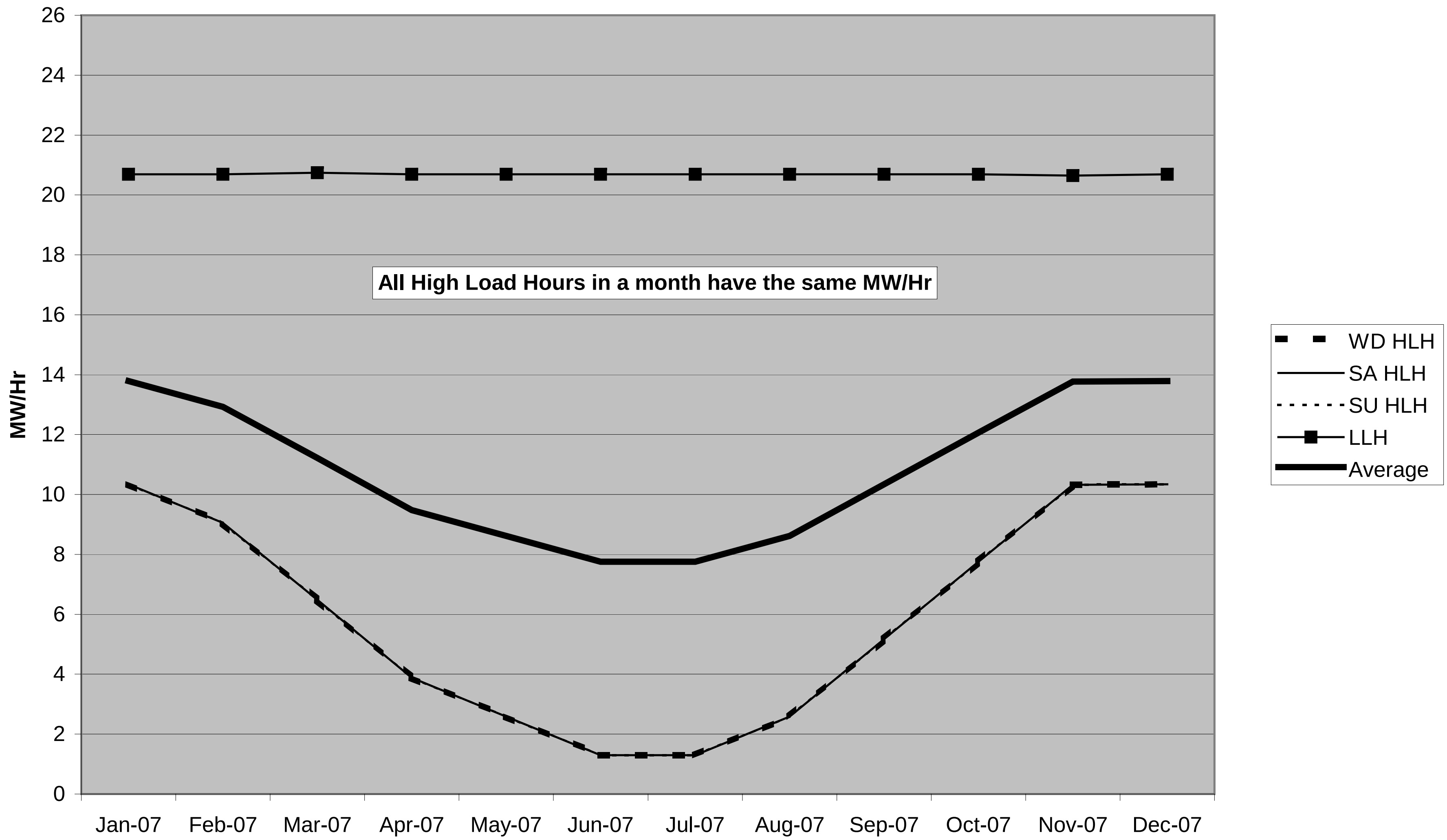


Figure 5.8

Total, Network
Usage Per Hour By Costing Period

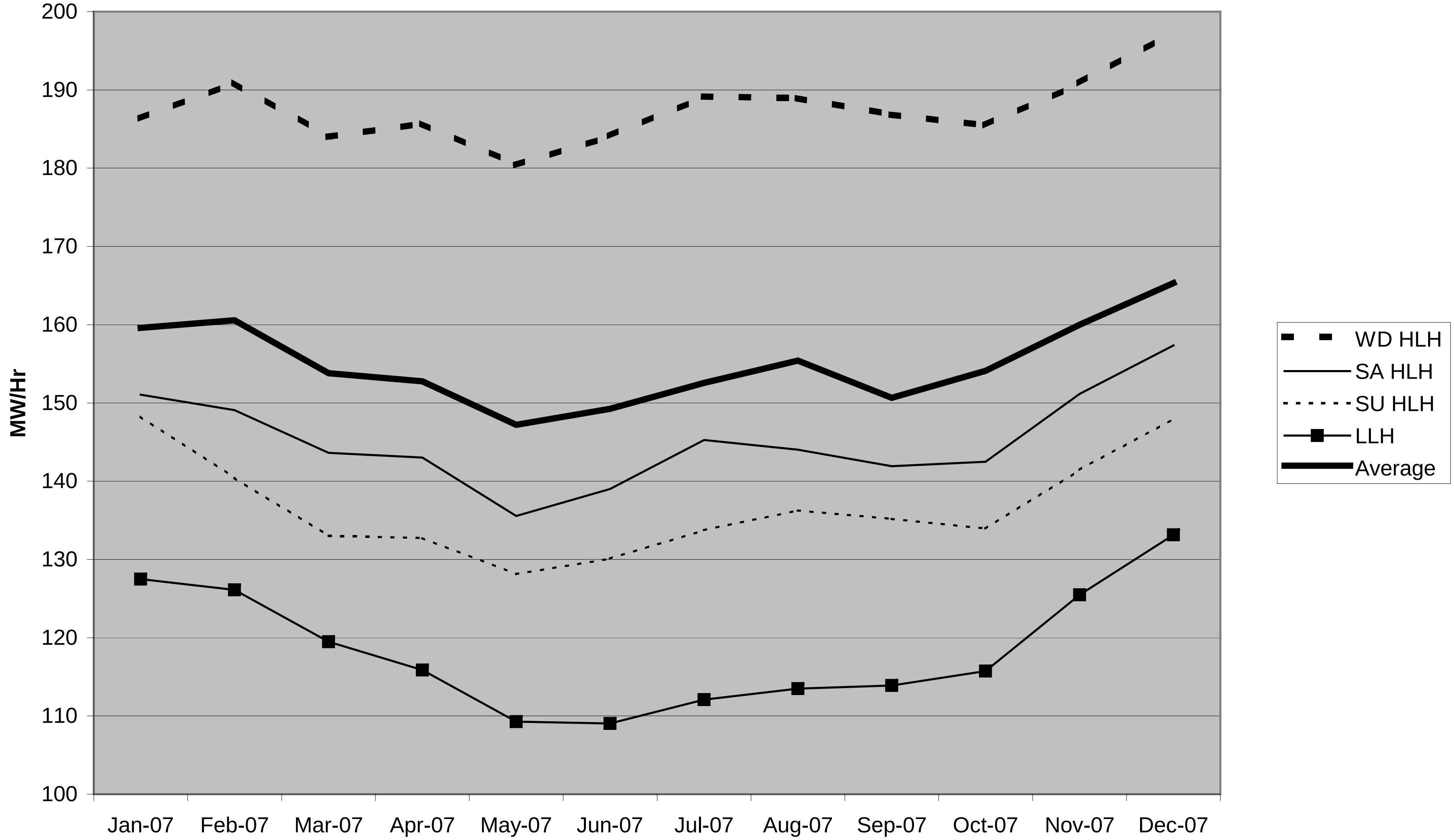


Figure 5.9

Residential, Network
Usage Per Hour By Costing Period

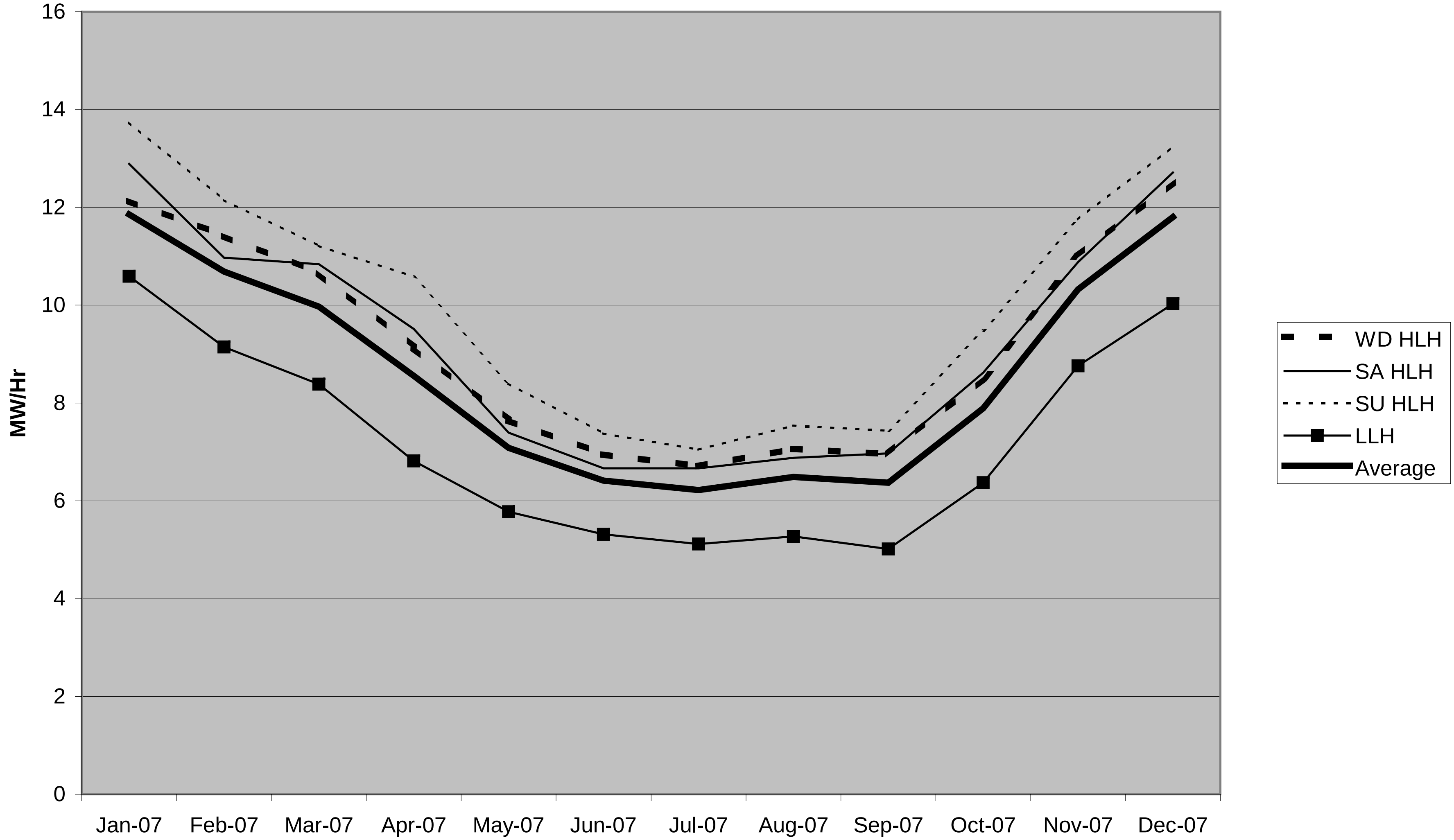


Figure 5.10

Small, Network
Usage Per Hour By Costing Period

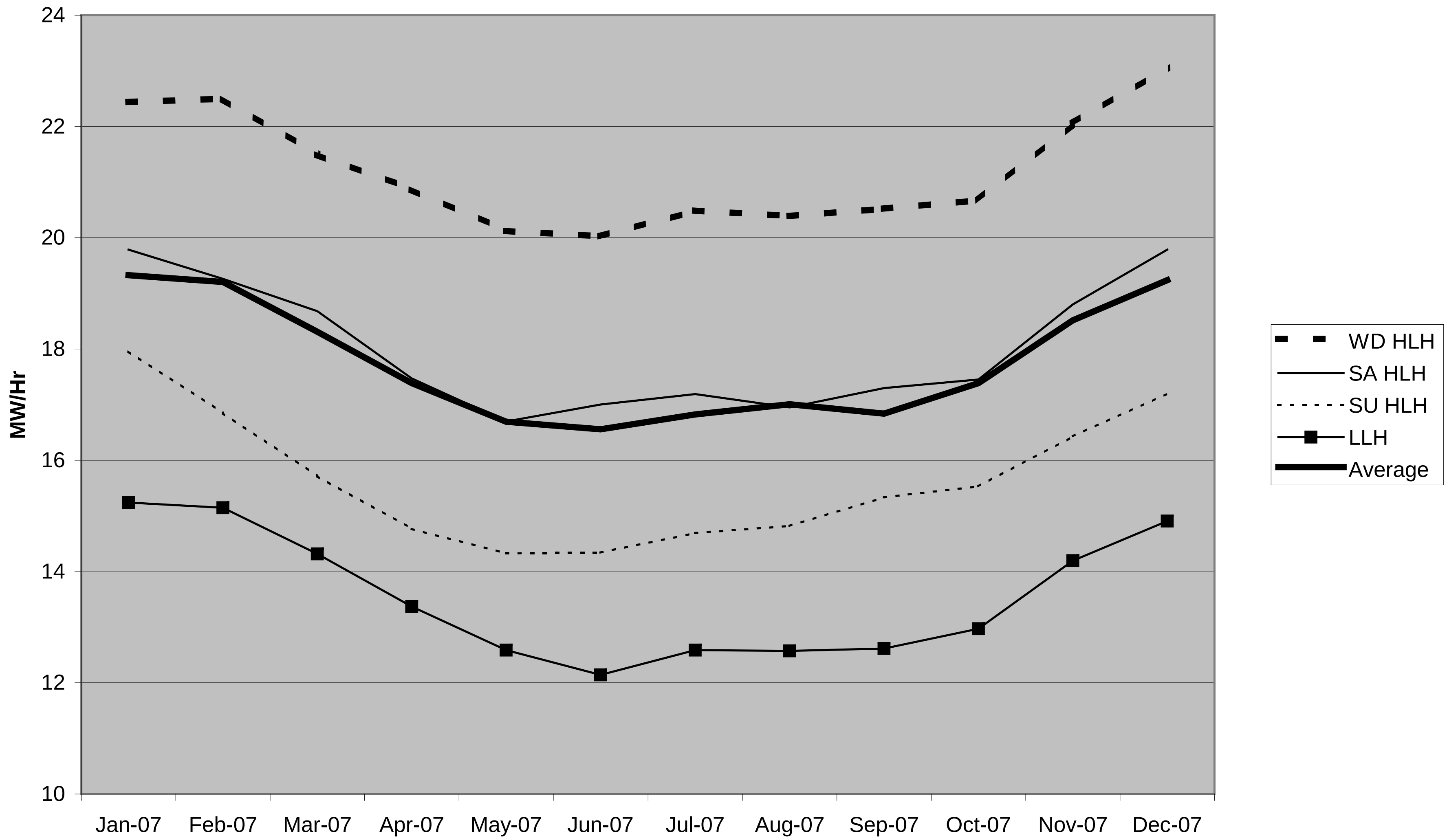


Figure 5.11

Medium, Network
Usage Per Hour By Costing Period

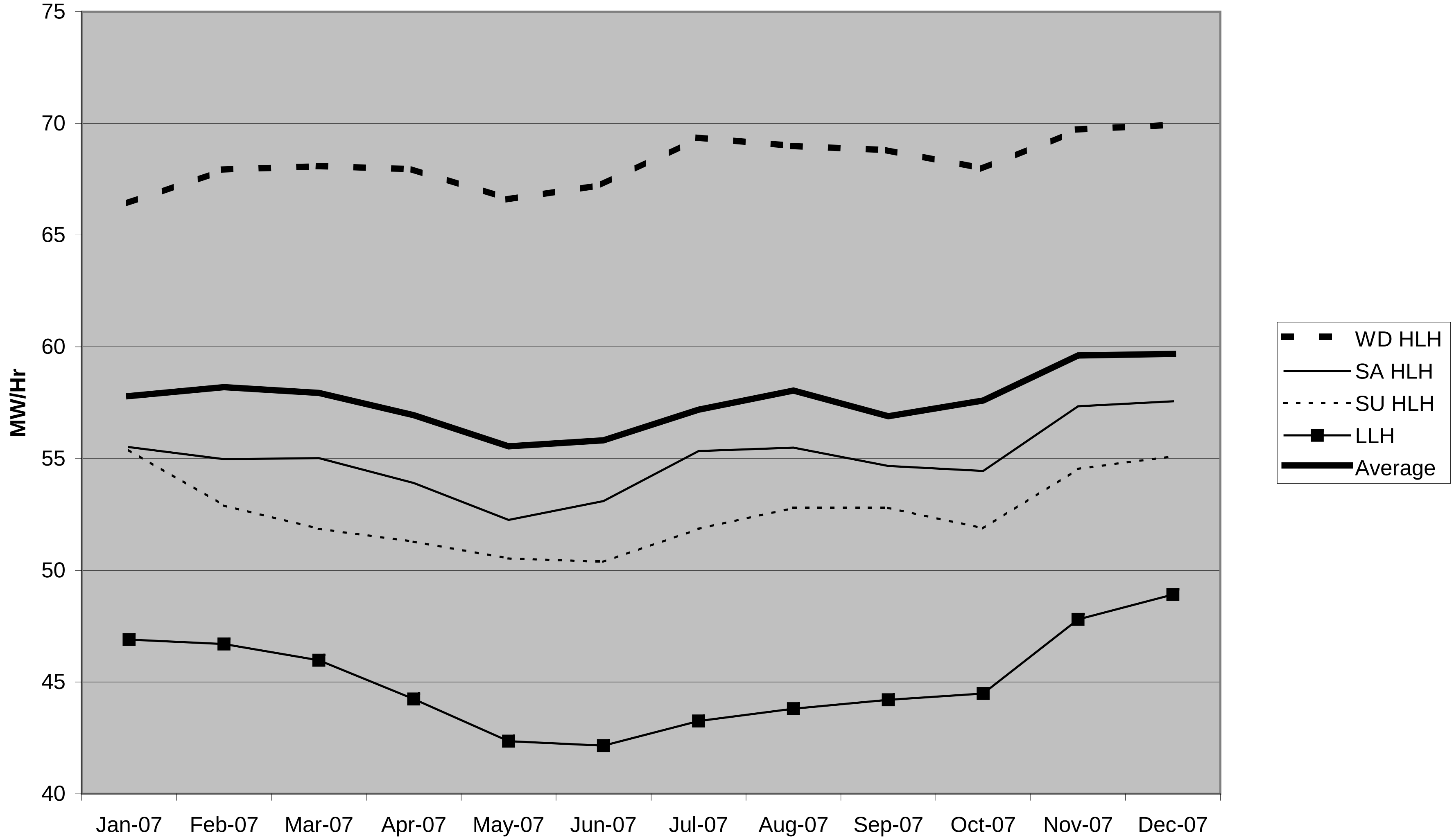


Figure 5.12

Large, Network
Usage Per Hour By Costing Period

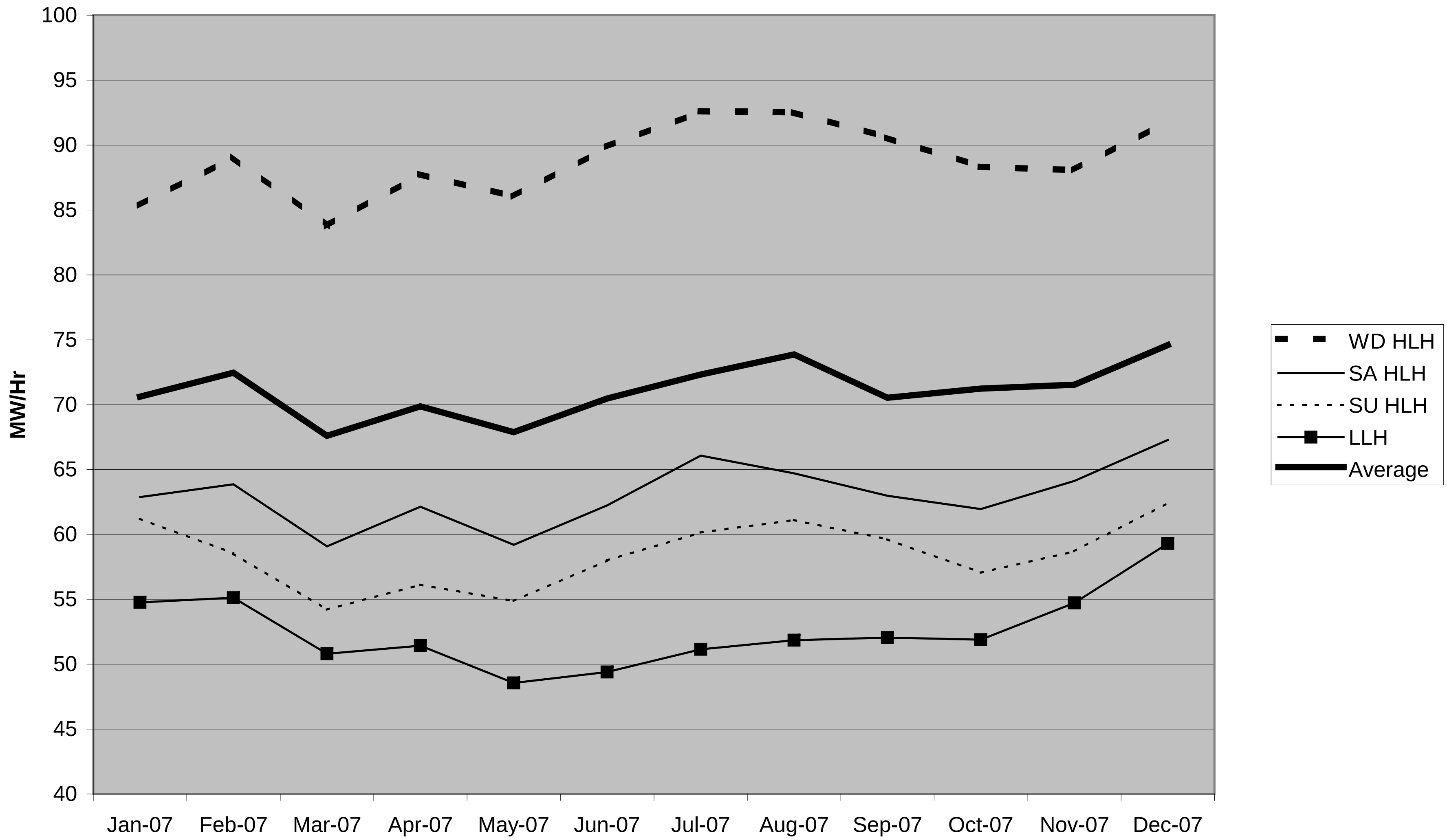
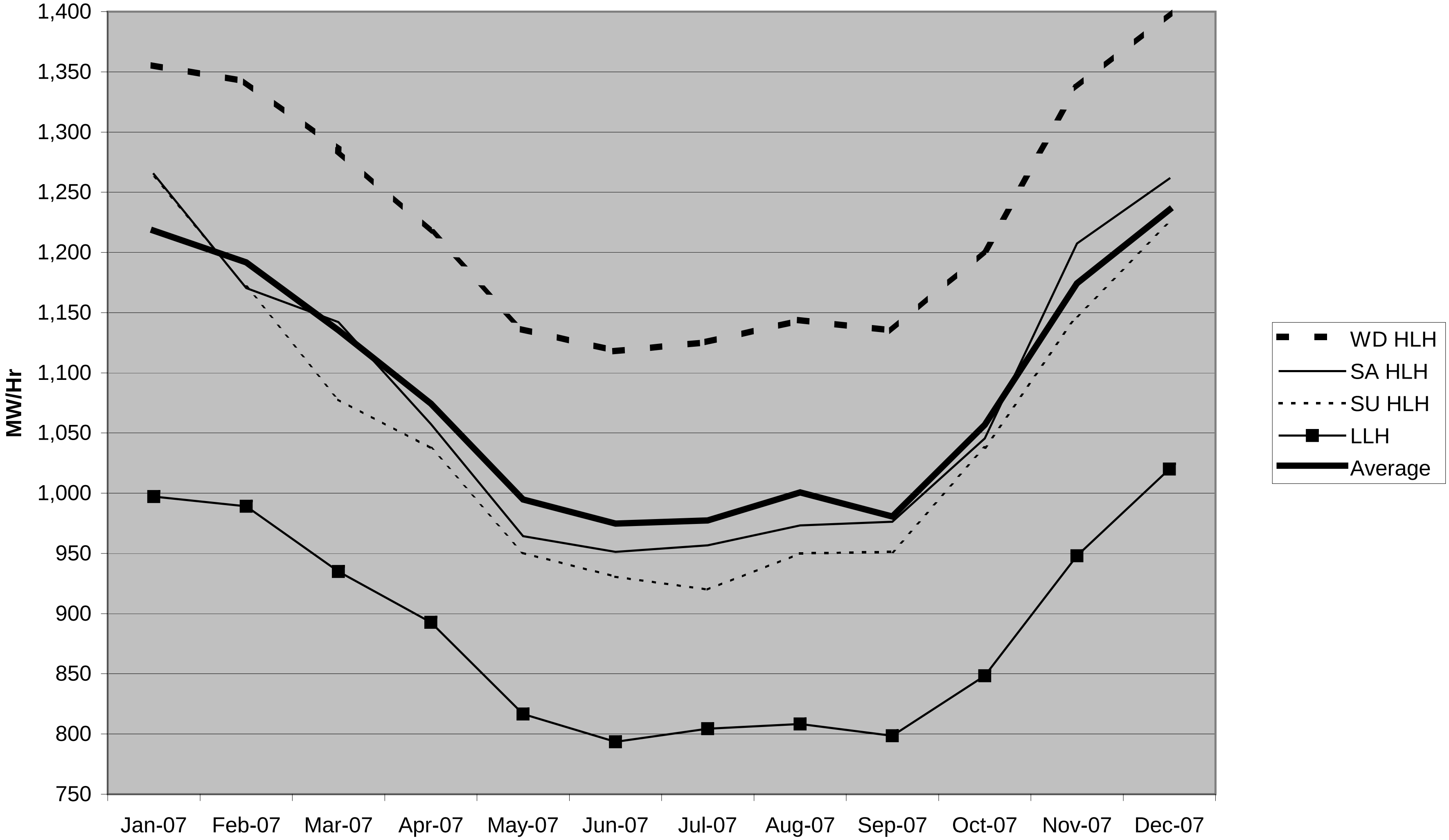


Figure 5.13

Total, Service Territory
Usage Per Hour By Costing Period



5.3 System Losses

As electrical energy is generated, transmitted and distributed to consumers, energy losses are incurred. Since load losses vary with the amount of current flowing, each increment in load will cause an associated incremental energy loss. This means that the total output of the system must be greater than the aggregate of all loads measured at the point of consumption. These losses increase the costs of providing electrical energy and must be accounted for in the marginal cost analysis.

This report accounts for the system losses by applying the estimates which are representative of Seattle City Light's system. Losses that characterize City Light's system are differentiated by type of facilities and by time periods. System losses for the periods of maximum loads are shown in **Table 5.7**.[6] Since voltage on the system is held essentially constant, *percent losses at time of other than maximum load,* where load is expressed as average MW during the period, are related to the percent loss at the time of maximum load by the equation:

$$\left(\frac{load\_in\_costing\_period}{maximum\_load\_over\_all\_costing\_periods}\right)^2 * (\%\_loss\_in\_peak\_period)$$

Losses as a percentage of load from the point of generation or the wholesale electricity trading hub to the high side of the receiving substation are the same for all classes, as are losses through the substation and feeders to the high side of the customer's transformer. However, the time period in which customer transformer losses are incurred vary, because the time period of peak demand on the distribution system varies by class, as indicated in Table 5.6. Losses through the customers transformers depend entirely on the load characteristics of the customers.

5.3.1 Network Losses

Separate estimates are made for system losses when network service is analyzed. Load losses created in a network are less than in a nonnetwork for transformers and feeders due to N-1 design loading. For example, a three-transformer spot network would load each transformer up to two-thirds of its capacity under normal conditions. The load losses would be 4/9 of the transformer's rated load losses.[7] This same 4/9 factor would apply to losses through network feeders since there are typically three feeders per customer. There would be no distinction in losses between network and nonnetwork customers, though, from the service territory boundary to the low side of a substation's transformer, nor in the service drop from a customer's transformer to the customer. In the case of

[6] The majority of the Department's bulk transmission flows over BP lines. BPA charges for transmission losses at 1.9 percent of load on the line. This energy is returned to BPA 168 hours (one week) later. Thus, computation of long distance transmission losses do not use the equation in the text, but, rather, are computed as 0.019* MWH in a period.

[7] $4/9 = (2/3)^2$, derived from the preceding equation.

network service for Medium and Large General Service customers, therefore, maximum losses for feeders and customer transformers equal 4/9 times the losses in the Table 5.7. Maximum network losses for feeders and customer transformers for Residential and Small General Service (network) customers are estimated to equal the corresponding network losses for Medium General Service customers, i.e., 4/9*0.82% and 4/9*0.95%, respectively

Table 5.7

SYSTEM LOSSES FOR PERIODS OF MAXIMUM LOADS
(% of load)

	Residential	Small General Service	Medium General Service	Large and High Demand General Service
From generation stations Through BPA high voltage lines outside of the service area	1.90	1.90	1.90	1.90
To boundary of the service area Through high voltage lines within the service area	1.14	1.14	1.14	1.14
To high side of substations Through substation	.74	.74	.74	.74
To low side of substations Through 26/13 kV lines	.82	.82	.82	.82
To high side of line transformer Through distribution transformer	1.36	1.45	.95	.86
To low side of distribution transformer Through lines and services	.41	.86	.03	.03
Subtotal of Losses from the Service Area Boundary to the Customer's Transformer	2.70	2.70	2.70	2.70
Subtotal of Service Drop and Line Transformer Losses	1.77	2.31	0.98	.89

Note: The energy and demand loss figures apply to the various components of the transmission and distribution system based on a fully converted 26 kV distribution system.

Table 5.8 presents an annual summary of all the losses which were derived by using projections of load in terms of average MW per hour by four costing periods for each month and the equations mentioned above. The table also presents the annual summary of total energy required to serve each customer class. There is a corresponding set of detailed tables presenting the MWH data by two costing periods each month by class supporting the annual summary of total energy.

Table 5.8
Energy Loss Data

MWH Energy Loss Data							
	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory							
2006	483,261	159,666	73,356	115,545	72,449	56,513	5,731
2007	491,594	161,569	74,636	118,116	73,824	57,711	5,738
2008	502,740	165,803	77,276	120,232	75,171	58,513	5,745
Total Nonnetwork (Excludes Residential & Small Network)							
2006	417,703	155,936	64,179	91,388	43,955	56,513	5,731
2007	424,821	157,824	65,338	93,481	44,729	57,711	5,738
2008	434,362	161,953	67,638	95,003	45,511	58,513	5,745
Downtown Network							
2006	65,559	3,731	9,177	24,157	28,494		
2007	66,774	3,745	9,298	24,635	29,095		
2008	68,377	3,850	9,639	25,229	29,660		

MWH Load + Energy Loss Data							
	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory							
2006	9,807,916	3,278,004	1,254,170	2,418,528	1,564,997	1,191,570	100,646
2007	9,987,818	3,334,026	1,277,640	2,469,511	1,594,528	1,211,460	100,653
2008	10,180,121	3,405,079	1,305,511	2,519,482	1,623,272	1,226,117	100,660
Total Nonnetwork (Excludes Residential & Small Network)							
2006	8,409,131	3,200,025	1,091,945	1,899,726	925,218	1,191,570	100,646
2007	8,562,595	3,254,698	1,112,701	1,940,257	942,826	1,211,460	100,653
2008	8,725,094	3,323,999	1,137,023	1,979,144	958,152	1,226,117	100,660
Downtown Network							
2006	1,398,786	77,980	162,225	518,802	639,779		
2007	1,425,224	79,328	164,939	529,254	651,702		
2008	1,455,026	81,080	168,489	540,338	665,120		

Share of Load + Energy Loss							
	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory							
2006	100.000%	33.422%	12.787%	24.659%	15.956%	12.149%	1.026%
2007	100.000%	33.381%	12.792%	24.725%	15.965%	12.129%	1.008%
2008	100.000%	33.448%	12.824%	24.749%	15.946%	12.044%	0.989%
Total Nonnetwork (Excludes Residential & Small Network) as % of Tot. Svc. Terr.							
2006	85.738%	32.627%	11.133%	19.369%	9.433%	12.149%	1.026%
2007	85.730%	32.587%	11.141%	19.426%	9.440%	12.129%	1.008%
2008	85.707%	32.652%	11.169%	19.441%	9.412%	12.044%	0.989%
Downtown Network as % of Tot. Svc. Terr.							
2006	14.262%	0.795%	1.654%	5.290%	6.523%		
2007	14.270%	0.794%	1.651%	5.299%	6.525%		
2008	14.293%	0.796%	1.655%	5.308%	6.534%		

5.4 Meters and Consumption per Meter

Table 5.9 presents estimates of meters by class for the forecast horizon. There is only slow and episodic change in the classes with larger consumption (Medium General Service and larger), hence their numbers are frozen at values currently known. Modest growth in Residential and Small classes are projected.

Table 5.9
Meters

	Total Service Territory					
	Total	Residential	Small	Medium	Large	High Demand
2005	382,438	336,673	42,615	2,993	147	10
2006	384,638	338,673	42,815	2,993	146	11
2007	386,838	340,673	43,015	2,993	146	11
2008	389,038	342,673	43,215	2,993	146	11

	Total Nonnetwork (EXcludes Network Residential & Small)					
	Total	Residential	Small	Medium	Large	High Demand
2005	366,402	324,490	39,312	2,500	90	10
2006	368,381	326,269	39,512	2,500	89	11
2007	370,540	328,228	39,712	2,500	89	11
2008	372,689	330,177	39,912	2,500	89	11

	Downtown Network				
	Total	Residential	Small	Medium	Large
2005	16,036	12,183	3,303	493	57
2006	16,257	12,404	3,303	493	57
2007	16,298	12,445	3,303	493	57
2008	16,349	12,496	3,303	493	57

Table 5.10 presents the average hourly consumption per meter for the year 2007 by class. Network residential customers consume less per meter than their nonnetwork counterparts. Network small, medium and large customers consume more per hour than their nonnetwork counterparts.

The profiles of hourly consumption per meter would look the same as the previous figures on total hourly consumption by class. The differences would be in the scale of the consumption. Table 5.10 allows one to get an approximation of what the adjusted scales would be.

Table 5.10
Average Hourly kWh Consumption per Meter for 2007

	Total Service Territory					
	Total	Residential	Small	Medium	Large	High Demand
Svc. Terr.	2.802	1.063	3.19	89.7	1,189	11,973
Nonnet	2.507	1.077	3.01	84.3	1,152	11,973
Netwk	9.515	0.693	5.38	116.8	1,247	

Chapter 6

Planning Values for Energy, Transmission Cost and Energy Cost Shares

6.1 Planning Values for Energy

Marginal costs of energy represent the single largest cost factor for the utility. These costs represent the cost to replace or acquire one additional MWH of electricity. This cost has two components: first, the wholesale cost of energy at a trading hub plus the cost to transmit the energy to the edge of the service area, and second, the cost to deliver the electricity to the customer and provide related customer services. The first component is called the marginal value of energy (MVE) to the system. When both cost components are combined, the result is the MVE to the customer. It is the MVE to the system that is documented here.

The full social cost of electricity includes more than just the direct costs indicated above. In particular, there are numerous external effects associated with producing and delivering electricity. Examples are air, water and soil contamination. These external effects may contribute to solar warming, adverse health effects, reduced visibility, damage to fish and wildlife, etc. These effects impose their own costs on society. Consequently, a more complete accounting for social costs of electricity include estimates of these environmental externalities. Those cost estimates are included here as externality cost “adders.” Details about these adders are provided below.

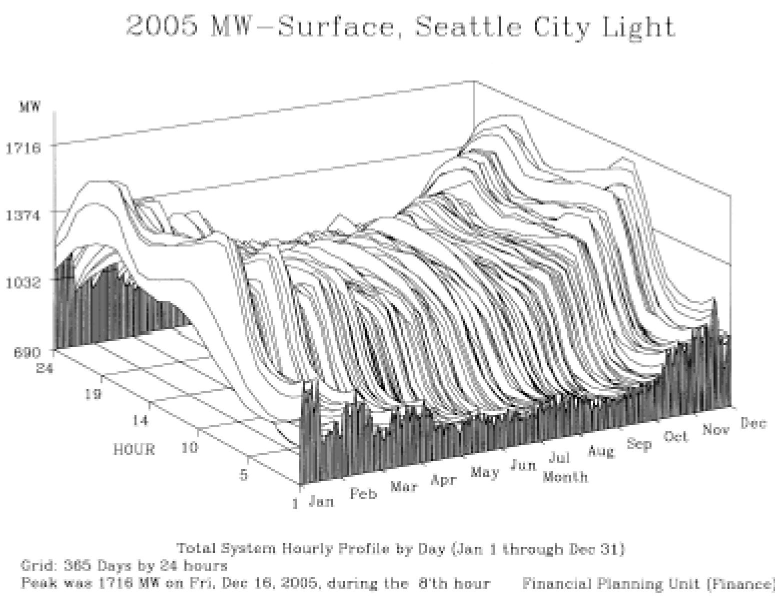
In previous years, prior to the development of open, competitive wholesale markets for energy on the west coast, the planning value for energy was estimated as the marginal cost of generation plus transmission.[8] In the latter part of the 1990’s, that previous method was replaced with a model that estimated the wholesale price of energy at trading points on the West Coast plus an explicit estimate of transmission costs. In the last several years, forecasts of electricity prices at wholesale hubs have been purchased from a highly respected industry consultant firm. The switch from use of an in-house produced forecast to purchase of an external forecast of wholesale electricity prices recognizes that the external firm can devote more time and resources to analysis than in-house staff.

Demand for electrical energy is instantaneous and the quantity demanded varies over time and in response to weather conditions. A colder day will result in increased electrical energy demand;

[8] A model, called the Annual Optimization Model-- or ANN, was meant to estimate the wholesale market value – or price -- for electricity since that is the direct cost that is socially relevant. The price for a product reflects both supply and demand conditions. One critique of ANN was that it was limited by data to using Seattle City Light loads and access to resources rather than the region’s loads and access to resources to estimate a market value. The advent of actual wholesale markets, and the opportunity to estimate prices in those markets, therefore, provided a conceptually superior estimate of direct social cost of electricity.

demand for electricity is higher during the day than after midnight; and weekend demand, when many businesses close or curtail their operations, is less than weekday demand. **Figure 6.1** shows the variation in electricity consumption by month, by season, by day of the week and by hour for Seattle City Light. Figures similar to this portray consumption for the northwest region. Supply conditions in this region of many hydroelectric plants are dictated to a great extent by rainfall and snow accumulation. Also affecting supply are the many rules and regulations imposed on the operation of hydro plants to protect against flooding, provide for irrigation and boating and, critically, providing for support of fish and wildlife.

Figure 6.1



Since the demand for electricity is so variable, and the various operations criteria are so strict, it should not be surprising that wholesale prices also vary significantly over the course of a year. There has been more stability over the course of a year recently than in the previous several years but at the same time, there can be relatively large fluctuations from one month to the next, as occurred in 2005. **Figure 6.2** presents an example of average electricity prices by costing period for 2003 through mid 2006 at the Mid-Columbia exchange hub

6.2 Costing Periods

There are 8,760 hours in a typical year. Wholesale prices are set by contract or by trades in each of those hours. Price data are often aggregated to simplify some presentations and analyses, such as in Figure 6.2. Wholesale price data are most commonly aggregated into 16 Peak hours and 8 Offpeak hours each day. Average prices at several wholesale exchange hubs are collected and published by the Dow Jones Corporation for each of those aggregated periods.

6.3 Energy Market Price Forecast

City Light purchases a market price forecast and analysis of spot market prices at the Mid-Columbia (Mid-C) and at a number of other exchange hubs. The price projections are for expected prices, averaged over all water conditions, rather than explicit forecasts for specific water conditions and the prices that would go with those conditions.

Figures 6.3 through 6.5 present the forecasts for Mid-Columbia prices used in this analysis. These figures present the spring, 2006 forecast. Figure 6.3 shows the annual forecast through 2015. There is a trend decline in expected prices till about 2009 when the trend begins to reverse itself and tilts upwards.

Figures 6.4 and 6.5 isolate the projections by month for Peak and Off-Peak periods for the two years of our rate case, 2007-2008. These figures indicate that there is an expectation that prices will decline in the spring and early summer, following the spring run-off that affects so many of the northwest hydro facilities. Otherwise, prices are expected to be higher in the autumn and winter.

Figure 6.2

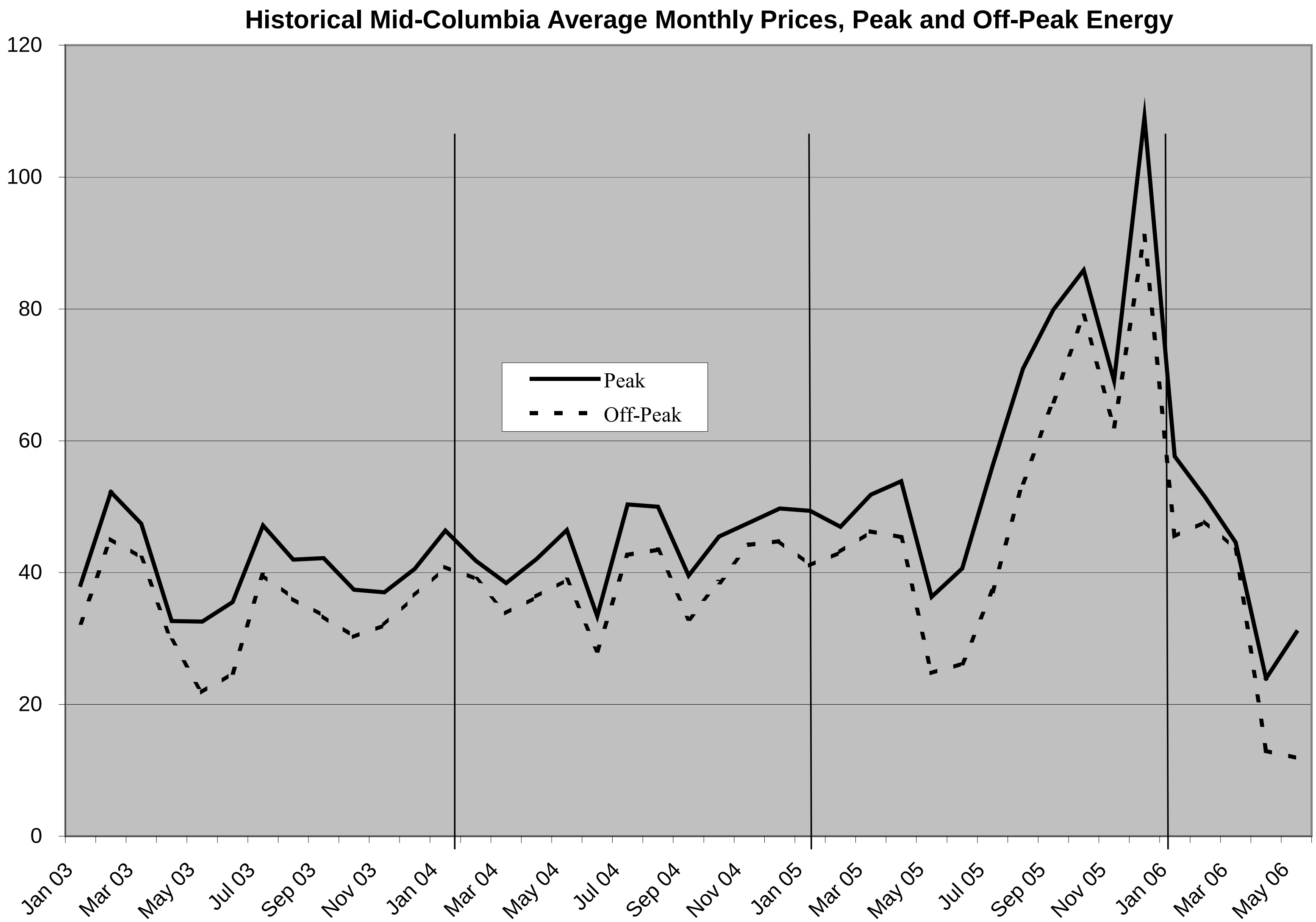

Historical Mid-Columbia Average Monthly Prices, Peak and Off-Peak Energy
120
100
80
60
40
20
0
Peak
Off-Peak
Jan 03
Mar 03
May 03
Jul 03
Sep 03
Nov 03
Jan 04
Mar 04
May 04
Jul 04
Sep 04
Nov 04
Jan 05
Mar 05
May 05
Jul 05
Sep 05
Nov 05
Jan 06
Mar 06
May 06

Figure 6.3

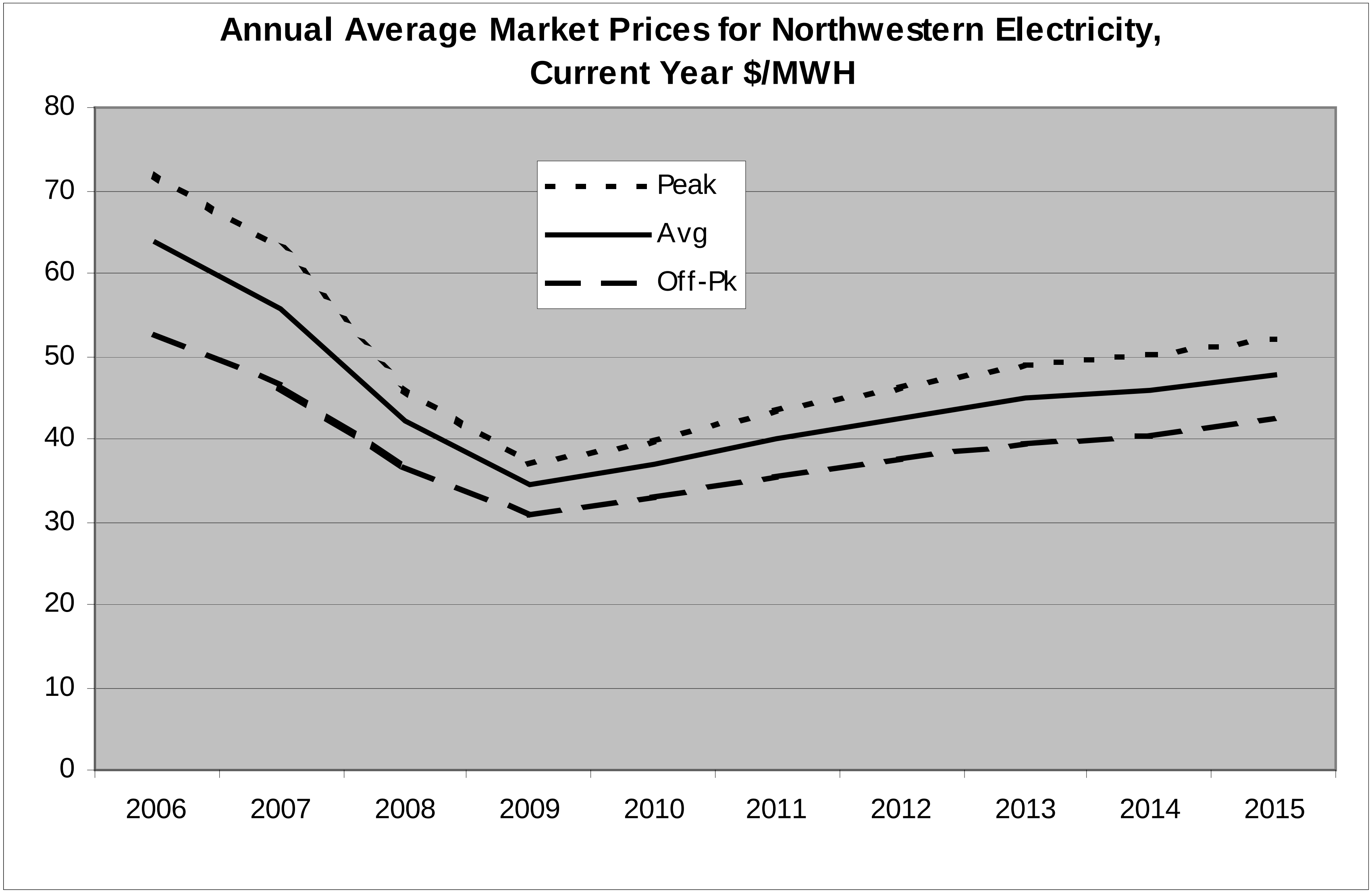

Annual Average Market Prices for Northwestern Electricity,
Current Year $/MWH
80
70
60
50
40
30
20
10
0
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
Peak
Avg
Off-Pk

Figure 6.4

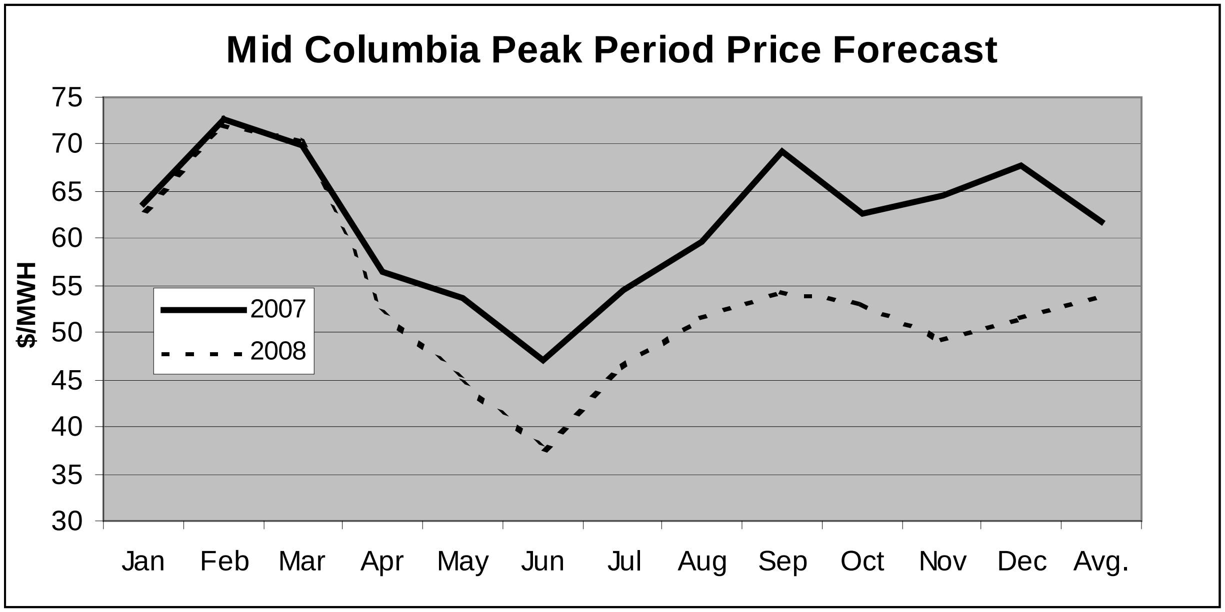
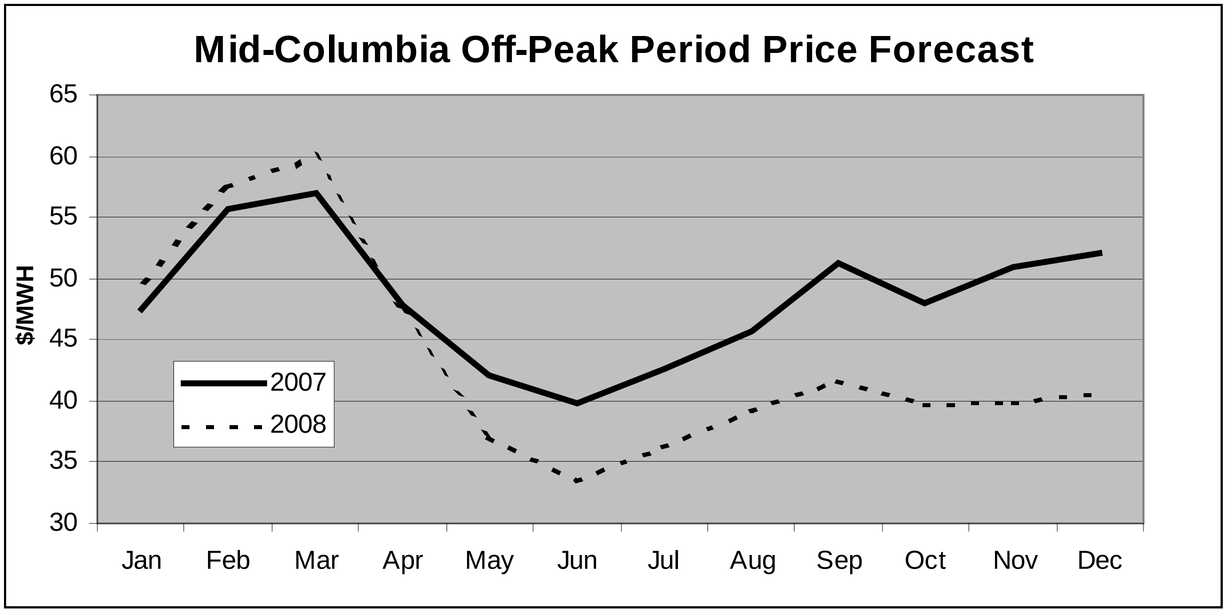


Figure 6.5



6.4 Externalities

For over a decade, Seattle City Light has used estimates of environmental externality costs for planning in a number of areas, including energy resource planning, rate setting, and valuation of conservation programs. Other departments in the City, including Finance and Seattle Public Utilities, have relied on City Light to provide estimates of environmental externality costs for electricity. These departments use these costs in evaluating various projects, including energy and water conservation.

The reasons for including environmental externality costs in the calculation of MVEs were described in *The Marginal Values of Energy 1994, Appendix* (August, 1994, SCL):

"Externalities are real costs paid by society but not reflected in a utility's cost of producing electricity. The primary reason for including externalities in the calculation of MVEs is to estimate the total societal costs of producing an additional unit of electricity…. Externalities should be included in the MVEs used for rate setting so the marginal cost targets used for pricing marginal consumption will include all costs of producing electricity. Only then will the best possible decisions be made about how much electricity to buy, what resources to use to produce it, and what levels of externalities (e.g. pollution) will be present in our environment as a result of electricity production and consumption."

SCL has used Marginal Values of Energy (MVEs) with externalities as a component of marginal cost calculations for the past several rate cases. Including externalities in MVEs has an impact on rate setting, particularly for residential end-block rates. For this rate process, it was also necessary to consider how to determine both MVEs and MVEs with externalities.

In the mid 1990s, City Light did a significant amount of work to collect and evaluate externality costs studies that had been produced by electric utilities and utility regulatory organizations. Around that time, environmental externality costs were receiving attention throughout the utility industry, and there was a range of data to choose from. City Light selected values from that range, and those externality costs for several air pollutants, carbon dioxide, and some land and water impacts were used in the 1996/97 resource planning process. As it turned out, the carbon dioxide component of the overall externality costs was by far the largest, due to the relatively large amount of emissions compared to other air emissions. In subsequent years, updates have been made to the carbon dioxide values, and these values have been used as a general, though not complete, representation of externality costs. As indicated above, an external industry consultant is the source for the basic wholesale price forecast used in this analysis

A challenge has been to find a method of including externalities that was consistent with a market price based MVE forecast and with past treatment of externalities.

In the summer of 2003, Seattle City Light reviewed the environmental externality adders that had been used in the 1999 Marginal Value of Energy (MVE) analysis. In September 2003, the externality values were revised. **Table 6.1** on the next page shows the estimated values from the years 2003 through 2023.

These values are based on the assumption that carbon dioxide (CO_2) emissions are the primary source of externality impacts from the marginal use of electricity. In this case, two variables must be determined in order to calculate the environmental externality adder for each year. One is the amount of CO_2 per MWH of marginal electricity and the other is the cost to the environment per unit of CO_2 emitted. Those values have been estimated for each year in the period 2003 through 2023 and multiplied together to result in the values in Table 6.1.

The amount of CO_2 emitted in the production of a MWH of electricity on the margin was estimated by determining emission rates for the years 2003 and 2023, and then performing a straight line interpolation between the two for the intervening years. This is a very simplistic approach, but it is impossible to know precisely what the mix of resources that make up the marginal MWH are going to be over the next few years, and impossible to know how the mix will change over the next 20 years. In 2003, SCL used the CO2 emission factor for the Environmental Protection Agency (EPA) Region 10 (which includes the northwest states) from a study done for the EPA (Cadmus Group, 1998). This emission factor is 0.545 metric tons of CO_2 per MWH, which is lower than the emission factor used on the last MVE process for that time period. For the year 2023, SCL estimated that the marginal resource would be almost entirely from relatively efficient natural gas plants (90%) with some coal (10%). Including coal is a change from the emission factor estimates from the 1999 MVE process, when it was assumed that all new marginal generation would be from natural gas plants. Due to uncertainty in the price and availability of natural gas supply, plans are being made to add new coal generation in the regions in which SCL buys electricity, so this resource was added to the

Table 6.1
Environmental Externality Adders

Year	Environmental Externality Adder (2003$ per MWH)
2003	$21.81
2004	$21.64
2005	$21.47
2006	$21.31
2007	$21.14
2008	$20.97
2009	$20.80
2010	$20.63
2011	$20.47
2012	$20.30
2013	$20.13
2014	$19.96
2015	$19.80
2016	$19.63
2017	$19.46
2018	$19.29
2019	$19.12
2020	$18.96
2021	$18.79
2022	$18.62
2023	$18.45

long term mix. The result is a higher emission factor in later years of the projection, compared to previous projections. The value assigned to each metric ton of CO_2 was $40, in year 2003 dollars, for every year. This value is meant to be an estimate of impacts of CO_2 emissions. While there is much uncertainty in this value, as described below, SCL believes that it generally reflects the potential costs of CO_2 emissions from electricity production.

Determining an exact dollar figure for the environmental impact of CO_2 emissions is not possible. There are numerous studies and models that predict a range of environmental, health, and social impacts of global climate change associated with anthropogenic CO_2 emissions, and some studies that estimate costs of these impacts. The ranges of per unit values are very wide. Also, most are representative of the costs from all anthropogenic CO_2 emissions, not only those from electricity production, and therefore cannot be translated into a per MWH value.

However, there has been some analysis done by environmental policy organizations and utilities that attempt to determine cost per unit of CO_2 emissions that would be necessary to cause behavioral change to reduce those emissions. Most focus on meeting some variation of the emissions-reductions goals for the United States, as set in the Kyoto Protocol. Some of the utility studies used estimates of what electricity producers might be charged per metric ton of CO_2 emissions, over a variety of regulatory scenarios. Results of these studies ranged from $8 to $100 per metric ton of CO_2.

The lower range represented the cost of purchasing "offsets" for CO_2 emissions. The concept behind an offset is that an organization that is required to reduce its emissions of CO_2 (or other greenhouse gases), either because of its own internal policy or as the result of regulation, can pay another organization to make the actual CO_2 reductions if that other organization can do so at a lower cost. Offsets are speculative, and do not provide the certainty of avoiding the CO_2 emissions altogether, and there are very few transactions for offsets, so it is difficult to get an accurate idea of what the cost will be in the future. So, the current CO_2 offsets cost is not a good proxy for the environmental impacts that externalities are supposed to represent.

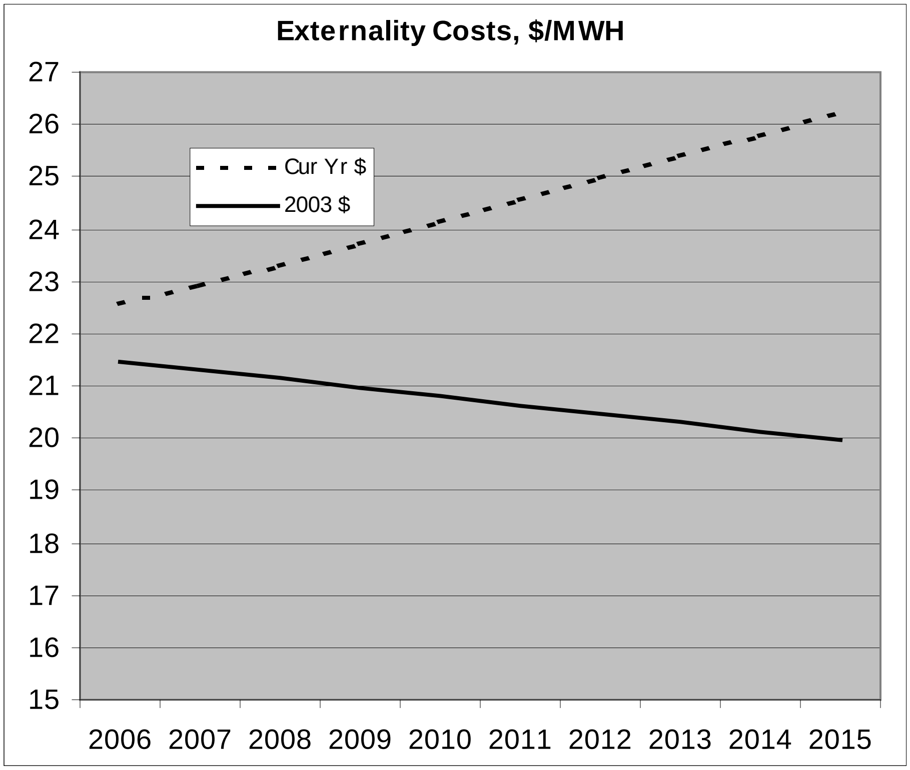
Instead, SCL chose a value that was in the same range as the per-ton cost used in the last version of the MVE process, and was in the mid range of estimates of prices needed to meet Kyoto - $40 per metric ton CO_2.

Figure 6.6 on the next page presents the annual values for externality values in constant $2003/MWH and in current year dollars. Externalities are expected to decline in terms of constant values but to rise in terms of current year prices.

6.4.1 On-Going Research on Externalities

City Light has searched for recent data on externality costs values as part of the 2006 Integrated Resource Plan (IRP) process, but found no new research had been done since the mid 1990s, with the exception of carbon dioxide. The work done on carbon dioxide was focused on analyzing the financial cost of meeting the Kyoto Protocol emissions limits, or some variation on those limits with respect to the level of the absolute cap and the timing of the limits. Other

Figure 6.6



studies looked at the very new carbon dioxide offset markets and reported on current and expected offset trading costs. However, in order to represent the impacts of non-carbon emissions in the IRP, City Light desires to include externality costs estimates for oxides of sulfur and nitrogen (SOX and NOX), mercury, and particulates, in addition to carbon dioxide. All of the non-carbon pollutants are being regulated under the Clean Air Act, and regulations released in Spring 2005 are expected to result in utilities installing more pollution controls on both new and existing power plants. This will internalize more of the air emission impacts, but there will still be remaining emissions.

6.4.2 Data Used for 2006 IRP

City Light asked the consultant to the IRP, Global Energy Decisions, to provide any information or research they had done on externality or emission costs. This data will be used as a proxy for environmental externalities. Global provided their estimates of the cost of pollution control measures at utility plants that will be required to meet the recent regulations. The values based on control costs are not the only way, or necessarily the best way, to represent environmental externality costs, but provide a representation of those costs. City Light does not have to select a single view of what the externality costs will be, but rather can present a range, as defined under the different sets of costs in the futures. This type of 'scenario planning' is a well-established concept in all types of planning processes.

The control cost data was provided for five different possible 'futures' in the IRP. Each future represents a set of price and regulatory conditions that could unfold over the next 20 years, and potentially different levels of emission limits and timing of those limits (compared to the recent regulations). Since there are so many uncertainties over the planning period, the futures function as test cases, to show how plans might perform under a variety of possible conditions. The future that is considered most likely is the Reference Case. The others, Terrorism and Turmoil, Return to Regulation, Green World, and Nuclear Resurgence, represent other possible, but less likely, outcomes.

City Light has supplemented Global's data where necessary. Global assumes that there will be no carbon dioxide limits under the Reference Case, Terrorism, and Return to Regulation, and therefore assigned a zero value to carbon dioxide. Since City Light will, at a minimum, have to meet its Net Zero greenhouse gas emissions goal, a value of $5 per ton was assigned to CO2 in those futures. City Light also used its 1996 estimates for particulates costs since that air pollutant was not included in the futures.

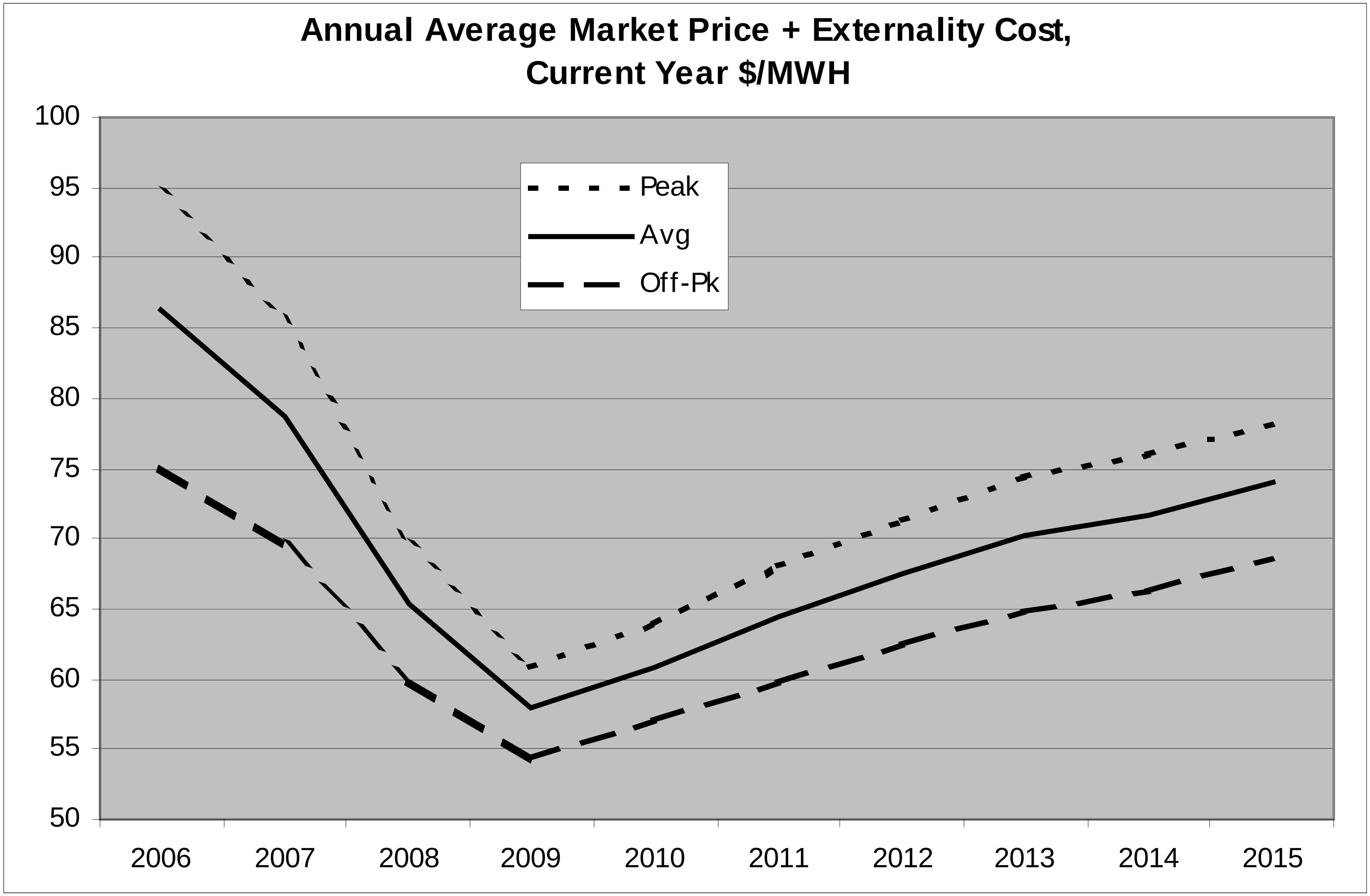
6.4.3 Recommendation

Reviewing these values and exploring how to apply them in the IRP analytical framework is still being discussed. Therefore, until the 2006 IRP process has concluded and a formal recommendation on the externality costs update has been made, the previous version of the cost estimates are the most reasonable externality values to use for planning purposes and for estimating the marginal values of energy with externalities.

6.5 Marginal Values of Energy with Externalities

Figures 6.7 through 6.9 present the planning values for energy, including externality costs, used in the analyses for this rate case. Figure 6.7 illustrates the annual average planning values with externality costs through 2015. Figures 6.8 and 6.9 illustrate the monthly values for 2007 and 2008 of peak and off-peak prices with externalities.

Figure 6.7



Annual Average Market Price + Externality Cost,
Current Year $/MWH
Peak
Avg
Off-Pk
100
95
90
85
80
75
70
65
60
55
50
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015

Figure 6.8

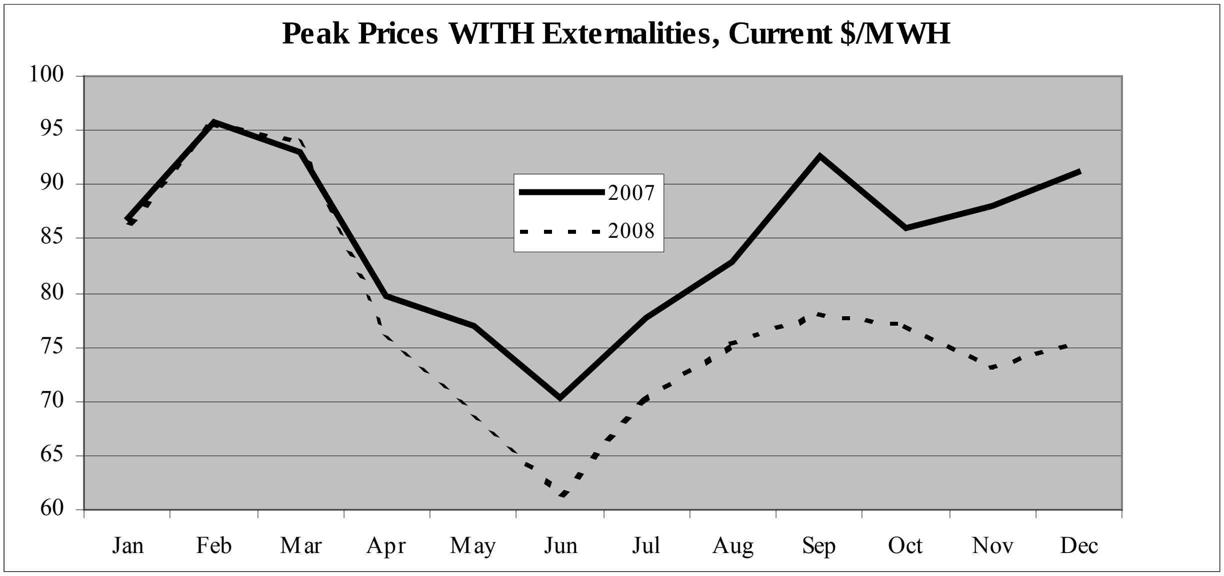
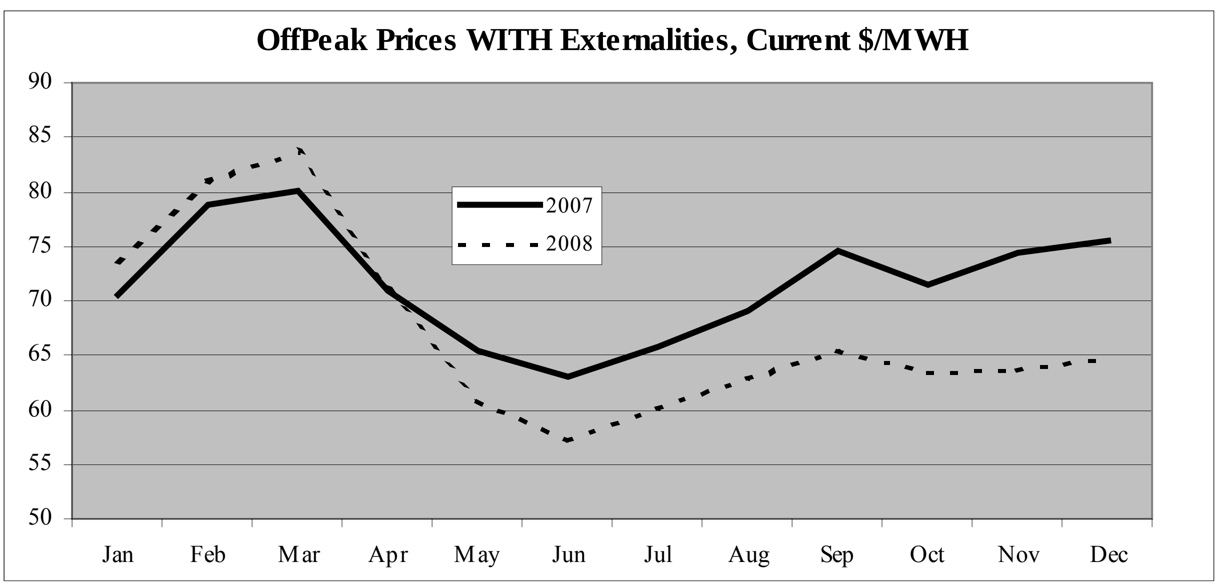


Figure 6.9



6.6 Value of Energy

Table 6.2 presents the annual summary of the value of energy by class. This value is determined by multiplying for each class, by each rate period (two per month), total load plus losses by projected market price plus externality adder, then summing results for each year. Note that the marginal value of energy declines in 2008 reflecting the expected drop in market wholesale prices for energy. The table also presents for each class the share of the service territory total value of energy. **Tables 6.3 through 6.5** present the costing period detail behind the annual value of energy shown in Table 6.2.

Table 6.2

Value of Energy (MVE+Externality)*(Load+Losses)

Total Service Territory

	Total	Residential	Small	Medium	Large	High Demand	Lights
2007	797,927,780	268,241,302	102,045,229	197,499,219	127,166,349	95,319,674	7,656,007
2008	750,582,102	253,874,525	96,104,446	185,462,707	119,130,478	88,891,526	7,118,421

Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)

	Total	Residential	Small	Medium	Large	High Demand	Lights
2007	683,913,698	261,883,182	88,858,628	155,259,602	74,936,605	95,319,674	7,656,007
2008	643,434,163	247,850,774	83,691,970	145,764,543	70,116,930	88,891,526	7,118,421

Downtown Network

	Total	Residential	Small	Medium	Large
2007	114,014,083	6,358,121	13,186,601	42,239,617	52,229,744
2008	107,147,940	6,023,751	12,412,476	39,698,164	49,013,549

Share of Value of Energy

Total Service Territory

	Total	Residential	Small	Medium	Large	High Demand	Lights
2007	100.000%	33.617%	12.789%	24.752%	15.937%	11.946%	0.959%
2008	100.000%	33.824%	12.804%	24.709%	15.872%	11.843%	0.948%

Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)

	Total	Residential	Small	Medium	Large	High Demand	Lights
2007	85.711%	32.820%	11.136%	19.458%	9.391%	11.946%	0.959%
2008	85.725%	33.021%	11.150%	19.420%	9.342%	11.843%	0.948%

Downtown Network

	Total	Residential	Small	Medium	Large
2007	14.289%	0.797%	1.653%	5.294%	6.546%
2008	14.275%	0.803%	1.654%	5.289%	6.530%

Table 6.3
Value of Energy by Costing Period (MVE+Externality)*(Load+Losses)

			Total Service Territory						
			Total	Residential	Small	Medium	Large	High Demand	Lights
Jan		Mon-Sa HLH	51,164,170	20,589,510	6,453,877	11,812,292	7,365,533	4,550,385	392,573
Jan		Other hrs	25,646,375	10,774,338	3,053,141	5,210,394	3,485,802	2,678,902	443,797
	2007	**Jan Total**	**76,810,545**	**31,363,848**	**9,507,017**	**17,022,686**	**10,851,334**	**7,229,287**	**836,371**
Feb		Mon-Sa HLH	50,947,572	19,080,006	6,618,065	12,103,717	7,739,497	5,057,233	349,053
Feb		Other hrs	24,354,021	9,434,259	2,872,231	5,082,029	3,440,707	3,090,958	433,837
	2007	**Feb Total**	**75,301,593**	**28,514,265**	**9,490,296**	**17,185,746**	**11,180,203**	**8,148,192**	**782,890**
Mar		Mon-Sa HLH	53,168,834	19,532,677	6,875,098	13,140,455	7,827,362	5,521,412	271,830
Mar		Other hrs	24,952,469	9,333,887	2,960,008	5,476,267	3,512,088	3,202,591	467,629
	2007	**Mar Total**	**78,121,303**	**28,866,564**	**9,835,107**	**18,616,722**	**11,339,450**	**8,724,002**	**739,459**
Apr		Mon-Sa HLH	39,797,232	13,024,223	5,222,923	10,366,859	6,506,654	4,547,961	128,612
Apr		Other hrs	21,869,435	7,627,186	2,566,079	4,911,002	3,292,888	3,078,203	394,077
	2007	**Apr Total**	**61,666,667**	**20,651,409**	**7,789,002**	**15,277,861**	**9,799,542**	**7,626,164**	**522,689**
May		Mon-Sa HLH	37,061,043	10,786,952	5,042,889	10,171,485	6,359,118	4,614,897	85,703
May		Other hrs	18,822,300	5,884,759	2,284,286	4,447,236	2,974,793	2,864,607	366,619
	2007	**May Total**	**55,883,344**	**16,671,711**	**7,327,175**	**14,618,721**	**9,333,911**	**7,479,504**	**452,322**
Jun		Mon-Sa HLH	33,179,284	8,994,719	4,565,086	9,243,982	6,011,375	4,324,929	39,194
Jun		Other hrs	16,294,684	4,593,689	1,993,383	4,000,195	2,740,281	2,632,491	334,644
	2007	**Jun Total**	**49,473,968**	**13,588,407**	**6,558,469**	**13,244,178**	**8,751,656**	**6,957,420**	**373,838**
Jul		Mon-Sa HLH	35,692,075	9,220,353	5,053,483	10,224,100	6,670,106	4,482,374	41,658
Jul		Other hrs	19,594,491	5,413,167	2,397,412	4,929,038	3,355,068	3,136,017	363,789
	2007	**Jul Total**	**55,286,565**	**14,633,519**	**7,450,895**	**15,153,138**	**10,025,175**	**7,618,391**	**405,447**
Aug		Mon-Sa HLH	41,853,455	11,141,993	5,776,119	11,699,683	7,708,800	5,430,886	95,975
Aug		Other hrs	18,666,021	5,182,066	2,273,018	4,722,918	3,228,475	2,874,832	384,713
	2007	**Aug Total**	**60,519,476**	**16,324,058**	**8,049,136**	**16,422,601**	**10,937,275**	**8,305,718**	**480,688**
Sep		Mon-Sa HLH	40,968,332	11,094,633	5,693,923	11,586,507	7,346,820	5,055,466	190,982
Sep		Other hrs	21,826,142	5,964,840	2,741,660	5,492,298	3,706,295	3,493,388	427,661
	2007	**Sep Total**	**62,794,474**	**17,059,474**	**8,435,583**	**17,078,805**	**11,053,115**	**8,548,854**	**618,644**
Oct		Mon-Sa HLH	45,856,726	14,309,419	6,065,590	12,129,387	7,650,291	5,401,949	300,090
Oct		Other hrs	20,467,347	6,455,064	2,463,689	4,790,221	3,267,504	3,068,497	422,373
	2007	**Oct Total**	**66,324,073**	**20,764,483**	**8,529,278**	**16,919,607**	**10,917,795**	**8,470,445**	**722,463**
Nov		Mon-Sa HLH	48,859,370	17,944,748	6,189,867	11,971,683	7,303,511	5,067,966	381,594
Nov		Other hrs	24,750,872	9,249,312	2,879,795	5,479,185	3,613,191	3,075,163	454,226
	2007	**Nov Total**	**73,610,242**	**27,194,060**	**9,069,662**	**17,450,868**	**10,916,702**	**8,143,129**	**835,820**
Dec		Mon-Sa HLH	52,917,587	20,916,226	6,660,169	12,317,918	7,839,255	4,787,116	396,903
Dec		Other hrs	29,217,945	11,693,276	3,343,439	6,190,368	4,220,937	3,281,451	488,474
	2007	**Dec Total**	**82,135,531**	**32,609,502**	**10,003,608**	**18,508,286**	**12,060,191**	**8,068,567**	**885,377**
Jan		Mon-Sa HLH	51,881,834	20,901,780	6,551,649	11,988,571	7,460,347	4,588,176	391,310
Jan		Other hrs	27,083,446	11,393,636	3,227,935	5,509,286	3,677,538	2,814,261	460,790
	2008	**Jan Total**	**78,965,280**	**32,295,416**	**9,779,584**	**17,497,858**	**11,137,885**	**7,402,437**	**852,100**
Feb		Mon-Sa HLH	53,840,290	20,179,875	7,008,127	12,809,669	8,174,924	5,317,308	350,388
Feb		Other hrs	26,057,119	10,102,469	3,079,969	5,448,475	3,682,298	3,300,629	443,279
	2008	**Feb Total**	**79,897,410**	**30,282,344**	**10,088,096**	**18,258,144**	**11,857,222**	**8,617,936**	**793,667**
Mar		Mon-Sa HLH	52,839,006	19,371,438	6,859,141	13,121,315	7,787,508	5,434,973	264,630
Mar		Other hrs	28,091,375	10,579,763	3,340,045	6,171,425	3,943,914	3,559,592	496,636
	2008	**Mar Total**	**80,930,381**	**29,951,201**	**10,199,186**	**19,292,741**	**11,731,422**	**8,994,565**	**761,266**
Apr		Mon-Sa HLH	40,038,554	13,201,636	5,246,768	10,389,660	6,516,500	4,556,378	127,612
Apr		Other hrs	20,888,131	7,262,165	2,452,412	4,694,056	3,144,827	2,945,840	388,832
	2008	**Apr Total**	**60,926,685**	**20,463,801**	**7,699,179**	**15,083,716**	**9,661,327**	**7,502,219**	**516,444**
May		Mon-Sa HLH	33,611,587	9,833,723	4,576,552	9,210,025	5,750,573	4,164,152	76,561
May		Other hrs	17,852,779	5,570,636	2,176,765	4,245,648	2,827,983	2,690,862	340,885
	2008	**May Total**	**51,464,366**	**15,404,360**	**6,753,317**	**13,455,673**	**8,578,556**	**6,855,014**	**417,447**
Jun		Mon-Sa HLH	28,491,823	7,683,349	3,942,307	7,989,895	5,177,799	3,665,568	32,905
Jun		Other hrs	15,934,057	4,553,854	1,954,589	3,904,359	2,667,958	2,548,473	304,823
	2008	**Jun Total**	**44,425,880**	**12,237,203**	**5,896,896**	**11,894,254**	**7,845,757**	**6,214,041**	**337,728**
Jul		Mon-Sa HLH	33,934,235	8,833,620	4,802,396	9,696,889	6,317,778	4,244,447	39,106
Jul		Other hrs	17,154,237	4,734,552	2,095,890	4,313,293	2,932,130	2,748,036	330,335
	2008	**Jul Total**	**51,088,472**	**13,568,173**	**6,898,286**	**14,010,182**	**9,249,908**	**6,992,483**	**369,441**
Aug		Mon-Sa HLH	37,242,096	9,905,688	5,158,577	10,434,683	6,859,315	4,799,937	83,897
Aug		Other hrs	18,385,883	5,131,071	2,258,221	4,678,627	3,183,684	2,781,612	352,668
	2008	**Aug Total**	**55,627,979**	**15,036,759**	**7,416,798**	**15,113,309**	**10,042,999**	**7,581,549**	**436,565**
Sep		Mon-Sa HLH	36,478,973	9,918,142	5,077,566	10,318,826	6,530,341	4,466,404	167,694
Sep		Other hrs	18,277,081	4,991,366	2,291,600	4,580,043	3,094,588	2,949,550	369,934
	2008	**Sep Total**	**54,756,054**	**14,909,508**	**7,369,166**	**14,898,868**	**9,624,929**	**7,415,954**	**537,629**
Oct		Mon-Sa HLH	41,678,824	13,022,257	5,528,307	11,039,868	6,947,450	4,872,199	268,742
Oct		Other hrs	18,447,412	5,828,194	2,227,323	4,326,180	2,943,052	2,747,398	375,265
	2008	**Oct Total**	**60,126,236**	**18,850,452**	**7,755,630**	**15,366,048**	**9,890,502**	**7,619,597**	**644,007**
Nov		Mon-Sa HLH	39,566,724	14,516,070	5,033,542	9,721,095	5,911,677	4,080,202	304,137
Nov		Other hrs	22,872,313	8,571,005	2,677,824	5,095,860	3,339,639	2,787,818	400,166
	2008	**Nov Total**	**62,439,037**	**23,087,076**	**7,711,366**	**14,816,955**	**9,251,316**	**6,868,021**	**704,304**
Dec		Mon-Sa HLH	46,082,517	18,264,684	5,806,141	10,725,399	6,816,405	4,128,558	341,330
Dec		Other hrs	23,851,805	9,523,549	2,730,802	5,049,560	3,442,250	2,699,151	406,493
	2008	**Dec Total**	**69,934,322**	**27,788,233**	**8,536,943**	**15,774,959**	**10,258,655**	**6,827,709**	**747,823**

Table 6.4
Value of Energy by Costing Period (MVE+Externality)*(Load+Losses)

		Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)						
		Total	Residential	Small	Medium	Large	High Demand	Lights
Jan	Mon-Sa HLH	44,305,065	20,123,241	5,609,390	9,360,194	4,269,282	4,550,385	392,573
Jan	Other hrs	22,464,912	10,499,917	2,669,409	4,035,899	2,136,987	2,678,902	443,797
2007	**Jan Total**	**66,769,977**	**30,623,158**	**8,278,799**	**13,396,093**	**6,406,269**	**7,229,287**	**836,371**
Feb	Mon-Sa HLH	43,840,827	18,641,170	5,760,613	9,565,899	4,466,858	5,057,233	349,053
Feb	Other hrs	21,312,653	9,202,464	2,505,075	3,951,615	2,128,704	3,090,958	433,837
2007	**Feb Total**	**65,153,480**	**27,843,634**	**8,265,689**	**13,517,514**	**6,595,561**	**8,148,192**	**782,890**
Mar	Mon-Sa HLH	45,740,315	19,082,104	5,983,796	10,378,143	4,503,032	5,521,412	271,830
Mar	Other hrs	21,802,519	9,102,127	2,582,023	4,260,717	2,187,432	3,202,591	467,629
2007	**Mar Total**	**67,542,834**	**28,184,231**	**8,565,819**	**14,638,859**	**6,690,464**	**8,724,002**	**739,459**
Apr	Mon-Sa HLH	33,827,607	12,717,923	4,538,832	8,175,238	3,719,042	4,547,961	128,612
Apr	Other hrs	19,053,285	7,444,846	2,243,064	3,832,195	2,060,901	3,078,203	394,077
2007	**Apr Total**	**52,880,893**	**20,162,769**	**6,781,896**	**12,007,432**	**5,779,943**	**7,626,164**	**522,689**
May	Mon-Sa HLH	31,267,744	10,533,779	4,383,318	8,021,963	3,628,086	4,614,897	85,703
May	Other hrs	16,305,715	5,742,966	1,995,732	3,466,942	1,868,849	2,864,607	366,619
2007	**May Total**	**47,573,459**	**16,276,745**	**6,379,050**	**11,488,905**	**5,496,935**	**7,479,504**	**452,322**
Jun	Mon-Sa HLH	27,815,590	8,784,904	3,966,094	7,271,280	3,429,189	4,324,929	39,194
Jun	Other hrs	14,052,466	4,480,130	1,743,496	3,132,611	1,729,093	2,632,491	334,644
2007	**Jun Total**	**41,868,056**	**13,265,034**	**5,709,590**	**10,403,892**	**5,158,283**	**6,957,420**	**373,838**
Jul	Mon-Sa HLH	29,765,974	9,003,546	4,398,991	8,041,139	3,798,266	4,482,374	41,658
Jul	Other hrs	16,833,537	5,281,114	2,088,425	3,861,805	2,102,388	3,136,017	363,789
2007	**Jul Total**	**46,599,511**	**14,284,660**	**6,487,416**	**11,902,944**	**5,900,654**	**7,618,391**	**405,447**
Aug	Mon-Sa HLH	35,025,535	10,879,917	5,025,859	9,191,673	4,401,225	5,430,886	95,975
Aug	Other hrs	16,037,707	5,054,570	1,982,166	3,707,217	2,034,209	2,874,832	384,713
2007	**Aug Total**	**51,063,242**	**15,934,487**	**7,008,025**	**12,898,891**	**6,435,434**	**8,305,718**	**480,688**
Sep	Mon-Sa HLH	34,364,720	10,837,092	4,949,488	9,136,954	4,194,737	5,055,466	190,982
Sep	Other hrs	18,723,552	5,817,454	2,394,040	4,285,240	2,305,769	3,493,388	427,661
2007	**Sep Total**	**53,088,272**	**16,654,546**	**7,343,529**	**13,422,194**	**6,500,506**	**8,548,854**	**618,644**
Oct	Mon-Sa HLH	38,897,625	13,978,879	5,274,397	9,567,305	4,375,007	5,401,949	300,090
Oct	Other hrs	17,720,418	6,293,810	2,152,126	3,732,274	2,051,339	3,068,497	422,373
2007	**Oct Total**	**56,618,043**	**20,272,689**	**7,426,522**	**13,299,579**	**6,426,345**	**8,470,445**	**722,463**
Nov	Mon-Sa HLH	42,037,286	17,538,248	5,385,615	9,468,142	4,195,721	5,067,966	381,594
Nov	Other hrs	21,554,372	9,013,678	2,513,885	4,257,445	2,239,975	3,075,163	454,226
2007	**Nov Total**	**63,591,658**	**26,551,926**	**7,899,499**	**13,725,587**	**6,435,696**	**8,143,129**	**835,820**
Dec	Mon-Sa HLH	45,648,647	20,432,456	5,790,637	9,732,357	4,509,178	4,787,116	396,903
Dec	Other hrs	25,515,626	11,396,849	2,922,157	4,825,356	2,601,339	3,281,451	488,474
2007	**Dec Total**	**71,164,273**	**31,829,305**	**8,712,794**	**14,557,713**	**7,110,516**	**8,068,567**	**885,377**
Jan	Mon-Sa HLH	44,922,052	20,428,157	5,695,152	9,499,384	4,319,873	4,588,176	391,310
Jan	Other hrs	23,720,617	11,103,278	2,822,624	4,267,336	2,252,327	2,814,261	460,790
2008	**Jan Total**	**68,642,669**	**31,531,435**	**8,517,776**	**13,766,721**	**6,572,199**	**7,402,437**	**852,100**
Feb	Mon-Sa HLH	46,318,397	19,714,555	6,100,895	10,122,359	4,712,892	5,317,308	350,388
Feb	Other hrs	22,796,628	9,853,542	2,686,426	4,236,055	2,276,697	3,300,629	443,279
2008	**Feb Total**	**69,115,024**	**29,568,096**	**8,787,321**	**14,358,414**	**6,989,590**	**8,617,936**	**793,667**
Mar	Mon-Sa HLH	45,432,622	18,924,671	5,970,241	10,369,379	4,468,727	5,434,973	264,630
Mar	Other hrs	24,533,430	10,317,721	2,913,558	4,798,794	2,447,129	3,559,592	496,636
2008	**Mar Total**	**69,966,052**	**29,242,392**	**8,883,799**	**15,168,173**	**6,915,856**	**8,994,565**	**761,266**
Apr	Mon-Sa HLH	34,044,905	12,890,530	4,560,312	8,186,369	3,723,704	4,556,378	127,612
Apr	Other hrs	18,204,181	7,088,583	2,144,277	3,665,205	1,971,444	2,945,840	388,832
2008	**Apr Total**	**52,249,086**	**19,979,113**	**6,704,589**	**11,851,574**	**5,695,148**	**7,502,219**	**516,444**
May	Mon-Sa HLH	28,357,538	9,603,058	3,977,630	7,259,879	3,276,257	4,164,152	76,561
May	Other hrs	15,453,609	5,436,006	1,902,246	3,311,928	1,771,681	2,690,862	340,885
2008	**May Total**	**43,811,146**	**15,039,064**	**5,879,877**	**10,571,807**	**5,047,937**	**6,855,014**	**417,447**
Jun	Mon-Sa HLH	23,859,221	7,503,744	3,425,215	6,288,634	2,943,156	3,665,568	32,905
Jun	Other hrs	13,733,288	4,441,853	1,708,830	3,052,990	1,676,318	2,548,473	304,823
2008	**Jun Total**	**37,592,509**	**11,945,597**	**5,134,045**	**9,341,624**	**4,619,474**	**6,214,041**	**337,728**
Jul	Mon-Sa HLH	28,304,841	8,625,735	4,180,429	7,621,001	3,594,124	4,244,447	39,106
Jul	Other hrs	14,744,755	4,618,757	1,825,918	3,381,142	1,840,566	2,748,036	330,335
2008	**Jul Total**	**43,049,595**	**13,244,492**	**6,006,347**	**11,002,142**	**5,434,690**	**6,992,483**	**369,441**
Aug	Mon-Sa HLH	31,147,324	9,672,688	4,487,805	8,197,570	3,905,427	4,799,937	83,897
Aug	Other hrs	15,771,835	5,004,987	1,969,643	3,670,702	1,992,222	2,781,612	352,668
2008	**Aug Total**	**46,919,159**	**14,677,675**	**6,457,449**	**11,868,272**	**5,897,650**	**7,581,549**	**436,565**
Sep	Mon-Sa HLH	30,591,767	9,687,573	4,414,318	8,133,432	3,722,345	4,466,404	167,694
Sep	Other hrs	15,690,599	4,867,617	2,001,195	3,571,777	1,930,526	2,949,550	369,934
2008	**Sep Total**	**46,282,367**	**14,555,190**	**6,415,514**	**11,705,209**	**5,652,871**	**7,415,954**	**537,629**
Oct	Mon-Sa HLH	35,339,841	12,721,282	4,807,195	8,706,102	3,964,320	4,872,199	268,742
Oct	Other hrs	15,964,990	5,682,529	1,945,673	3,370,116	1,844,009	2,747,398	375,265
2008	**Oct Total**	**51,304,831**	**18,403,812**	**6,752,869**	**12,076,218**	**5,808,329**	**7,619,597**	**644,007**
Nov	Mon-Sa HLH	34,026,543	14,187,615	4,379,156	7,689,391	3,386,041	4,080,202	304,137
Nov	Other hrs	19,899,141	8,353,508	2,337,500	3,961,120	2,059,029	2,787,818	400,166
2008	**Nov Total**	**53,925,685**	**22,541,124**	**6,716,656**	**11,650,510**	**5,445,070**	**6,868,021**	**704,304**
Dec	Mon-Sa HLH	39,744,061	17,842,187	5,048,581	8,469,107	3,914,298	4,128,558	341,330
Dec	Other hrs	20,831,979	9,280,596	2,387,149	3,934,771	2,123,819	2,699,151	406,493
2008	**Dec Total**	**60,576,040**	**27,122,783**	**7,435,730**	**12,403,878**	**6,038,117**	**6,827,709**	**747,823**

Table 6.5
Value of Energy by Costing Period (MVE+Externality)*(Load+Losses)

			Downtown Network				
			Total	Residential	Small	Medium	Large
Jan		Mon-Sa HLH	6,859,105	466,269	844,487	2,452,098	3,096,251
Jan		Other hrs	3,181,462	274,421	383,731	1,174,495	1,348,815
	2007	**Jan Total**	**10,040,567**	**740,690**	**1,228,218**	**3,626,593**	**4,445,066**
Feb		Mon-Sa HLH	7,106,745	438,836	857,452	2,537,818	3,272,639
Feb		Other hrs	3,041,368	231,795	367,156	1,130,414	1,312,003
	2007	**Feb Total**	**10,148,114**	**670,632**	**1,224,608**	**3,668,232**	**4,584,642**
Mar		Mon-Sa HLH	7,428,519	450,574	891,302	2,762,312	3,324,330
Mar		Other hrs	3,149,951	231,760	377,985	1,215,550	1,324,655
	2007	**Mar Total**	**10,578,469**	**682,334**	**1,269,288**	**3,977,863**	**4,648,986**
Apr		Mon-Sa HLH	5,969,624	306,300	684,091	2,191,621	2,787,612
Apr		Other hrs	2,816,150	182,340	323,015	1,078,807	1,231,988
	2007	**Apr Total**	**8,785,774**	**488,640**	**1,007,106**	**3,270,429**	**4,019,600**
May		Mon-Sa HLH	5,793,299	253,173	659,571	2,149,522	2,731,032
May		Other hrs	2,516,585	141,793	288,554	980,294	1,105,944
	2007	**May Total**	**8,309,884**	**394,966**	**948,126**	**3,129,816**	**3,836,976**
Jun		Mon-Sa HLH	5,363,694	209,815	598,992	1,972,702	2,582,186
Jun		Other hrs	2,242,218	113,559	249,887	867,584	1,011,188
	2007	**Jun Total**	**7,605,912**	**323,374**	**848,879**	**2,840,286**	**3,593,373**
Jul		Mon-Sa HLH	5,926,101	216,807	654,492	2,182,961	2,871,841
Jul		Other hrs	2,760,953	132,052	308,987	1,067,233	1,252,680
	2007	**Jul Total**	**8,687,054**	**348,860**	**963,479**	**3,250,194**	**4,124,521**
Aug		Mon-Sa HLH	6,827,919	262,076	750,260	2,508,009	3,307,574
Aug		Other hrs	2,628,314	127,495	290,852	1,015,701	1,194,266
	2007	**Aug Total**	**9,456,233**	**389,571**	**1,041,112**	**3,523,710**	**4,501,840**
Sep		Mon-Sa HLH	6,603,612	257,542	744,435	2,449,553	3,152,083
Sep		Other hrs	3,102,590	147,386	347,619	1,207,058	1,400,526
	2007	**Sep Total**	**9,706,202**	**404,928**	**1,092,054**	**3,656,611**	**4,552,609**
Oct		Mon-Sa HLH	6,959,101	330,541	791,193	2,562,082	3,275,285
Oct		Other hrs	2,746,929	161,254	311,563	1,057,947	1,216,165
	2007	**Oct Total**	**9,706,030**	**491,795**	**1,102,756**	**3,620,029**	**4,491,450**
Nov		Mon-Sa HLH	6,822,084	406,500	804,253	2,503,542	3,107,790
Nov		Other hrs	3,196,500	235,635	365,910	1,221,740	1,373,216
	2007	**Nov Total**	**10,018,584**	**642,135**	**1,170,162**	**3,725,282**	**4,481,005**
Dec		Mon-Sa HLH	7,268,940	483,770	869,532	2,585,561	3,330,077
Dec		Other hrs	3,702,318	296,427	421,282	1,365,012	1,619,598
	2007	**Dec Total**	**10,971,259**	**780,198**	**1,290,814**	**3,950,572**	**4,949,675**
Jan		Mon-Sa HLH	6,959,781	473,623	856,497	2,489,187	3,140,475
Jan		Other hrs	3,362,830	290,358	405,311	1,241,950	1,425,211
	2008	**Jan Total**	**10,322,611**	**763,981**	**1,261,808**	**3,731,137**	**4,565,686**
Feb		Mon-Sa HLH	7,521,894	465,320	907,232	2,687,310	3,462,032
Feb		Other hrs	3,260,492	248,928	393,543	1,212,421	1,405,600
	2008	**Feb Total**	**10,782,385**	**714,248**	**1,300,775**	**3,899,730**	**4,867,632**
Mar		Mon-Sa HLH	7,406,384	446,767	888,900	2,751,936	3,318,781
Mar		Other hrs	3,557,945	262,042	426,487	1,372,631	1,496,785
	2008	**Mar Total**	**10,964,329**	**708,809**	**1,315,387**	**4,124,567**	**4,815,566**
Apr		Mon-Sa HLH	5,993,649	311,106	686,456	2,203,291	2,792,796
Apr		Other hrs	2,683,951	173,582	308,135	1,028,851	1,173,384
	2008	**Apr Total**	**8,677,599**	**484,688**	**994,590**	**3,232,142**	**3,966,179**
May		Mon-Sa HLH	5,254,049	230,665	598,922	1,950,146	2,474,316
May		Other hrs	2,399,171	134,630	274,519	933,720	1,056,302
	2008	**May Total**	**7,653,220**	**365,295**	**873,441**	**2,883,866**	**3,530,618**
Jun		Mon-Sa HLH	4,632,602	179,605	517,092	1,701,261	2,234,644
Jun		Other hrs	2,200,769	112,001	245,759	851,369	991,640
	2008	**Jun Total**	**6,833,371**	**291,606**	**762,851**	**2,552,630**	**3,226,284**
Jul		Mon-Sa HLH	5,629,395	207,885	621,967	2,075,888	2,723,654
Jul		Other hrs	2,409,483	115,795	269,972	932,151	1,091,564
	2008	**Jul Total**	**8,038,877**	**323,680**	**891,939**	**3,008,040**	**3,815,218**
Aug		Mon-Sa HLH	6,094,772	233,000	670,771	2,237,113	2,953,888
Aug		Other hrs	2,614,048	126,084	288,578	1,007,924	1,191,462
	2008	**Aug Total**	**8,708,820**	**359,084**	**959,349**	**3,245,037**	**4,145,350**
Sep		Mon-Sa HLH	5,887,206	230,569	663,247	2,185,394	2,807,996
Sep		Other hrs	2,586,481	123,749	290,405	1,008,266	1,164,062
	2008	**Sep Total**	**8,473,687**	**354,318**	**953,652**	**3,193,659**	**3,972,058**
Oct		Mon-Sa HLH	6,338,983	300,975	721,112	2,333,766	2,983,130
Oct		Other hrs	2,482,422	145,665	281,649	956,064	1,099,043
	2008	**Oct Total**	**8,821,405**	**446,640**	**1,002,761**	**3,289,830**	**4,082,174**
Nov		Mon-Sa HLH	5,540,181	328,455	654,386	2,031,705	2,525,636
Nov		Other hrs	2,973,172	217,497	340,324	1,134,740	1,280,610
	2008	**Nov Total**	**8,513,352**	**545,952**	**994,710**	**3,166,444**	**3,806,246**
Dec		Mon-Sa HLH	6,338,456	422,497	757,560	2,256,292	2,902,107
Dec		Other hrs	3,019,826	242,953	343,653	1,114,789	1,318,431
	2008	**Dec Total**	**9,358,282**	**665,450**	**1,101,213**	**3,371,081**	**4,220,539**

6.7 Long Distance Transmission Costs

Energy generation occurs outside the service territory and requires transmission services to get power to the service territory. Every customer class utilizes transmission services, regardless of the size of their load and regardless of the timing of their load. The majority of transmission services used by the Department are sold by the Bonneville Power Administration. BPA transmission services are purchased via long term contract. A fixed quantity of transmission services is purchased for a multi-year period. The analysis here, though, acts as if transmission services were purchased one year at a time so that an 'optimal' amount of transmission can be obtained for each year. The amount purchased has to be large enough to service the peak MW load during the year in order to guarantee serving the load throughout the year.

("Guarantee" is meant in a common contractual sense. There can not be a guarantee against catastrophes caused by natural forces, war, or such.)

In order to guarantee serving the peak load during the year, it is necessary to purchase sufficient transmission services to serve the system peak load. The following discussion presents the derivation of transmission cost by customer class assuming that City Light were a distribution company only, buying all the energy needed to serve its retail load from the wholesale market.

Transmission Capacity needed to serve annual load equals some percent times the annual average load (=Annual retail load in MWH/8760). **200%** is used in the analysis here. This value approximates fairly closely the relationship between the annual average City Light system load and the peak system load observed in the past**.** From Table 5.6 we see that **annual average load for 2007 equals 1,084 MW and for 2008 equals 1,102 MW.**. **Transmission capacity required for 2007,** therefore**, equals 2,168 MW and capacity required for 2008 equals 2,204MW.**

The price for BPA transmission services is $1,216/MW per month.

The process used here to determine long distance transmission costs by class starts with an estimation of the total cost of transmission services for the entire Department. These annual costs for transmission equal $31,635,456 for 2007 and $32,160,768 for 2008. The cost of transmission must be allocated among customer classes. If the total cost is assigned on the basis of each class' share of the peak load, it would be possible for a class to receive a small share if it had little load during the peak period. In this case, the class with a small load during the system peak would have transmission services paid for by the classes taking load during the peak period. This fact would reflect the reality of the particular load configuration served. But the fact would violate the commonsense notion that every class requires transmission services to get wholesale energy delivered to them. A procedure to acknowledge that fact was developed.

The procedure to allocate the net transmission cost among classes developed an estimate of the quantity of transmission services needed to serve each class on its own, as if it were the only class being served.[9] The results were summed over all classes. Shares of the cost of transmission from this set of calculations were then used to allocate the costs of transmission from the analysis of the actual system load.

This process allows assignment of a "reasonable" fraction of the net cost of transmission services to each customer class and at the same time preserves a useful estimate of the marginal value of transmission services for each customer class. **Table 6.6** presents the annual cost of transmission services for the various classes.

Table 6.6
Long Distance Transmission Costs

	Total Service Territory						
	Total	Residential	Small	Medium	Large	High Demand	Lights
2007 Total	$ 31,635,456	10,568,635	4,007,654	7,833,372	5,066,031	3,843,567	316,197
	100.000%	33.408%	12.668%	24.761%	16.014%	12.150%	1.000%
2008 Total	$ 32,160,768	10,765,062	4,081,784	7,973,410	5,144,792	3,880,290	315,430
	100.000%	33.473%	12.692%	24.792%	15.997%	12.065%	0.981%

	Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)						
	Total	Residential	Small	Medium	Large	High Demand	Lights
2007 Total	$ 27,109,954	10,316,840	3,489,156	6,152,298	2,991,895	3,843,567	316,197
	85.695%	32.612%	11.029%	19.447%	9.457%	12.150%	1.000%
2008 Total	$ 27,552,528	10,508,404	3,553,879	6,261,552	3,032,973	3,880,290	315,430
	85.671%	32.675%	11.050%	19.470%	9.431%	12.065%	0.981%

	Downtown Network				
	Total	Residential	Small	Medium	Large
2007 Total	4,525,502	251,795	518,498	1,681,074	2,074,136
	14.305%	0.796%	1.639%	5.314%	6.556%
2008 Total	4,608,240	256,658	527,905	1,711,858	2,111,819
	14.329%	0.798%	1.641%	5.323%	6.566%

6.7.3 Note: comparison with 2001-2002 COSACAR treatment of Long Distance Transmission

The last COSACAR adjusted transmission costs by subtracting expected revenue from sale of surplus transmission capacity available during the portions of the year when the total transmission capacity was not used. The approach here does not make that adjustment. An argument for excluding the adjustment is that expected revenue from those sales are already taken into account in determining total revenue requirements, or, equivalently, net transmission revenue requirements. Hence, the only task is to allocate the joint transmission cost among the revenue classes. An argument for using the adjustment is that the value of surplus transmission sales is higher in HLH than in LLH so classes with low usage in HLH could be charged less. The share of load in HLH is

[9] Following the procedure for calculating the amount of capacity for the total system, the amount of capacity 'purchased' for each class in this synthetic exercise would be 200% of the average load for each class. Inspection reveals that each class will, therefore, be allocated the same percentage of the total system transmission costs as their share of load as shown at the bottom of Table 5.5.

very similar for all classes (but streetlights) so the relative adjustment would be negligible. Since all classes require transmission, and since the costs assigned to streetlights without the adjustment is already low, there was no material justification for performing these extra calculations.

6.8 Total Energy Cost Shares

The total marginal cost of energy equals the sum of the energy plus losses valued at market prices plus externality costs and costs of transmission. **Table 6.7** presents the results from previous tables of the two components of total energy costs, derives the sum of the two, and computes each class share of the total for the service territory. The shares derived from the sum of the marginal costs for the two years are used to allocate all components of the functionalized energy revenue requirements summed for those years.

Table 6.7
Derivation of Total Energy Cost Shares

		Total Service Territory						
		Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
2007	Energy + Losses	797,927,780	268,241,302	102,045,229	197,499,219	127,166,349	95,319,674	7,656,007
	Transmission	31,635,456	10,568,635	4,007,654	7,833,372	5,066,031	3,843,567	316,197
	Total Energy Cost	829,563,236	278,809,937	106,052,883	205,332,591	132,232,380	99,163,242	7,972,204
	Share	100.000%	33.609%	12.784%	24.752%	15.940%	11.954%	0.961%
2008	Energy + Losses	750,582,102	253,874,525	96,104,446	185,462,707	119,130,478	88,891,526	7,118,421
	Transmission	32,160,768	10,765,062	4,081,784	7,973,410	5,144,792	3,880,290	315,430
	Total Energy Cost	782,742,870	264,639,587	100,186,231	193,436,116	124,275,271	92,771,816	7,433,851
	Share	100.000%	33.809%	12.799%	24.713%	15.877%	11.852%	0.950%
2007+'08	Energy + Losses	1,548,509,883	522,115,827	198,149,676	382,961,926	246,296,827	184,211,200	14,774,427
	Transmission	63,796,224	21,333,697	8,089,438	15,806,781	10,210,823	7,723,857	631,627
	Total Energy Cost	1,612,306,107	543,449,524	206,239,114	398,768,707	256,507,650	191,935,057	15,406,055
	Share	100.000%	33.706%	12.792%	24.733%	15.909%	11.904%	0.956%

		Total Nonnetwork (EXcludes Network Residential & Small)						
		Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
2007	Energy + Losses	683,913,698	261,883,182	88,858,628	155,259,602	74,936,605	95,319,674	7,656,007
	Transmission	27,109,954	10,316,840	3,489,156	6,152,298	2,991,895	3,843,567	316,197
	Total Energy Cost	711,023,651	272,200,022	92,347,784	161,411,900	77,928,501	99,163,242	7,972,204
	Share	85.711%	32.812%	11.132%	19.457%	9.394%	11.954%	0.961%
2008	Energy + Losses	643,434,163	247,850,774	83,691,970	145,764,543	70,116,930	88,891,526	7,118,421
	Transmission	27,552,528	10,508,404	3,553,879	6,261,552	3,032,973	3,880,290	315,430
	Total Energy Cost	670,986,691	258,359,178	87,245,850	152,026,094	73,149,903	92,771,816	7,433,851
	Share	85.722%	33.007%	11.146%	19.422%	9.345%	11.852%	0.950%
2007+'08	Energy + Losses	1,327,347,861	509,733,956	172,550,599	301,024,144	145,053,535	184,211,200	14,774,427
	Transmission	54,662,481	20,825,244	7,043,035	12,413,850	6,024,868	7,723,857	631,627
	Total Energy Cost	1,382,010,342	530,559,199	179,593,634	313,437,994	151,078,403	191,935,057	15,406,055
	Share	85.716%	**32.907%**	**11.139%**	**19.440%**	**9.370%**	**11.904%**	**0.956%**

		Downtown Network				
		Total	**Residential**	**Small**	**Medium**	**Large**
2007	Energy + Losses	114,014,083	6,358,121	13,186,601	42,239,617	52,229,744
	Transmission	4,525,502	251,795	518,498	1,681,074	2,074,136
	Total Energy Cost	118,539,585	6,609,916	13,705,099	43,920,691	54,303,879
	Share	14.289%	0.797%	1.652%	5.294%	6.546%
2008	Energy + Losses	107,147,940	6,023,751	12,412,476	39,698,164	49,013,549
	Transmission	4,608,240	256,658	527,905	1,711,858	2,111,819
	Total Energy Cost	111,756,180	6,280,409	12,940,381	41,410,022	51,125,368
	Share	14.278%	0.802%	1.653%	5.290%	6.532%
2007+'08	Energy + Losses	221,162,022	12,381,871	25,599,077	81,937,781	101,243,292
	Transmission	9,133,743	508,453	1,046,403	3,392,932	4,185,955
	Total Energy Cost	230,295,765	12,890,324	26,645,480	85,330,713	105,429,247
	Share	14.284%	**0.799%**	**1.653%**	**5.292%**	**6.539%**

Chapter 7

Distribution Costs

7.1 Overview

Distribution revenue requirements are composed of:

In-service area transmission
Substations
Wires & related equipment
Customer transformers
Meters (excluding meter reading)
Streetlights

This chapter presents the derivation of cost shares by customer class that allocate all but one of these revenue requirements related to distribution. The exception is streetlights, all of whose revenue requirements are assigned to the streetlight rate class. Customer classes refer specifically to all classes in the total nonnetwork area and all classes in the downtown network area. Network residential and small customers are, at this stage, treated as network customers.

All of the indicated equipment and facilities are necessary to provide distribution service to existing and new customers. Maintenance and replacement when the equipment and facilities reach the end of their service life are necessary to provide service to existing and new load. Cost shares by customer class are developed in four steps. First, estimates of annualized capital costs and annual operations and maintenance costs per MW for the indicated component over the entire system are developed. Second, these per unit costs are multiplied by an appropriate peak load for each class. Third, the sum of these costs over all classes is computed. Finally, each class's share of these total costs is computed. These costs also are converted to costs of the forecast year, which has no effect on computing shares of cost, but is important later in providing information on marginal cost to rate analysts who, to the extent possible, set marginal rates as close as practicable to marginal costs.

7.2 In-Service Area Transmission

This functional revenue requirement is associated with the cost of facilities to transport energy from the boundary of the service territory through high voltage lines to substations where the energy is transformed to lower voltage to be distributed over feeders to retail customers.

7.2.1 Capital Costs: In-Service Area Transmission

The department's in-service area high-voltage transmission lines have a peak capacity of 2,892 MW. **Table 7.1** presents in terms of $2004 the capital cost associated with replacing the in-service area transmission lines. The cost estimates per mile come from the department's engineers reflecting their recent experience in replacing some major in-service area transmission lines. The mileage data represent the miles of line within the service territory at the two voltage levels indicated. Chapter 4 indicated that expected service life for this type of equipment is 45 years. Using the annualization factor from Chapter 4, the annualized cost of this equipment, therefore, is $25,256,778.[10] Dividing this by the capacity of the system indicates that the annual capital cost per MW equals $8,733.[11]

Table 7.1
In-Service Area Transmission, Replacement Cost of Capital
$2004

115 kV	miles	million$/Mile	total, million$
Overhead	97.21	2	194.46
Underground	21.1	5	105.5
Subtotal	118.33	2.535	299.96
230 kV			
Overhead	92.88	2.3	213.624
Underground	19.15	6	114.9
Subtotal	112.03	2.932	328.524
Total	230.36	2.728	**628.484**

The capacity must cover all the losses on the system. To somewhat simplify the analysis, the losses over all shared equipment cover the in-service transmission losses, substation losses and feeder losses. The sum of these common losses, from Chapter 5, is 2.7 percent. Thus, the **cost per MW, adjusted for losses, equals $8,976**.[12]

7.2.2 Annual Operations and Maintenance Costs: In-Service Area Transmission

Annual O&M costs for the in-service area transmission system have averaged around $1.5 million for a number of years. The actual costs, though, have been subjected to various financial constraints and 'catch-up' imposed on the department over the past several years. Hence, an average of costs over a two year period was considered to be the most reasonable representation of O&M costs for these facilities. **Table 7.2** presents the costs associated with in-service area transmission per FERC (Federal Energy Regulatory Commission) account for 2003 and 2004. The average of these costs, $1,505,217, was used as a representation for annual O&M costs. Subsequent to the data developed for this rate-case analysis, data for the year 2005 became available. Those data are shown, too, and indicate that the average for 2003 and 2004 is very similar. The total annual O&M

[10] Annual cost for 45 year asset with the indicated total capital cost = 0.040186828 * 628,484,000 = 25,256,778.
[11] Annual cost per MW = 25,256,778/2,892 = 8,733.33/MW.
[12] Loss adjusted cost = 8,733.33/(1-0.027) = 8,976.

cost divided by the capacity of the in-service system produces an **annual O&M cost per MW of $520.48**.[13]

Table 7.2
Annual FERC Costs for In-Service Area Transmission

In Service Transmission O & M	FERC #	2003	2004	2005
OS&E-INSIDE SEATTLE	56016	64,609.84	28,849.02	58,743.25
O-STATION EXP, INSIDE SEATTLE	56216	81,218.23	80,177.09	80,207.40
OP OV LINE EXP-INSIDE SEATTLE	56316	3,977.19	258,719.69	3,852.29
OP UN LINE EXP-INSIDE SEATTLE	56416	20,631.69	52,301.40	23,673.05
OP MISC L EXP-INSIDE SEATTLE	56616	29,675.38	229,208.30	257.73
MS&E-INSIDE SEATTLE	56816	33,499.96	33,469.74	30,266.60
MAINT TRANS ST-INSIDE SEATTLE	56916	67,213.18	51,911.09	41,650.53
MAINT RELAY SE-INSIDE SEATTLE	57016	41,543.97	78,356.94	284,010.58
MAINT STAT EQ-INSIDE SEATTLE	57026	373,814.38	707,866.64	545,351.17
ROADS & TRAILS-INSIDE SEATTLE	57116	118,849.72	127,283.33	98,043.91
TOWERS & POLES-INSIDE SEATTLE	57126	7,778.96	5,868.89	10,096.03
M O/H TRANS CO-INSIDE SEATTLE	57136	17,018.84	219,781.59	4,422.61
CLR TREE&BRSH-INSIDE SEATTLE	57146	108,839.08	88,959.18	397,844.84
MAINT O/H ENG-INSIDE SEATTLE	57156	-	17,806.10	-
U/G NON ELEC EQ-INSIDE SEATTLE	57216	25,554.24	9,553.94	-
U/G ELEC EQ-INSIDE SEATTLE	57226	26,742.59	56,044.72	3,804.20
U/G ELEC ACCESS-INSIDE SEATTLE	57236	3,872.57	23,487.93	5,391.19
U/G MAINT ENG-INSIDE SEATTLE	57246	154.54	1,256.48	1,093.30
MISC TRANS PLA-INSIDE SEATTLE	57316	3,537.42	4,459.87	1,165.04
SUBTOTAL (excl 56016 - a supervisory cost)		963,921.94	2,046,512.92	1,531,130.47
Average of 2003 & 2004		**1,505,217.43**		

7.2.3 Cost Shares: In-Service Area Transmission

Cost shares by class for the nonnetwork and network classes are developed in **Table 7.3** on the next page. These cost calculations begin with the load of each class at the time of the system peak load. These data come from Table 5.6 in Chapter 5. Those loads are multiplied by the capital cost and O&M cost per MW. The sum of these costs is computed, then converted to dollars of the forecast year. The service territory total of costs over all classes is computed and shares by class of this total cost are computed. Shares used to allocate the sum of revenue requirements for 2007 and 2008 are derived by adding the total marginal costs for each those years and dividing by the sum of costs for the total service territory.

7.3 Substations

High voltage power delivered by the in-service area transmission lines must be transformed to lower voltages to be carried over distribution feeder lines that deliver power near to individual customers. Whereas there are no differences in cost for in-service transmission (nor for costs of power delivered to the service territory boundary) between network and nonnetwork customers, there are some differences in the capital costs of substations that serve nonnetwork and those that serve network customers.

[13] Annual O&M cost per MW = 1,505,217/2,892 = 520.48.

7.3.1 Capital Costs: Substations

The department has, at various times in the past decade, considered building a new, 120 MW, substation in the InterBay area (in the valley between the Magnolia and Queen Ann

Table 7.3
Derivation of Cost Shares for In-Service Area Transmission

Coincident Loads, Loads at Time of System Peak Demand

		Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)						
		Total	Residential	Small	Medium	Large	High Demand	Lights
Period of Peak Load	2007	Dec WD HLH						
	2008	Dec WD HLH						
Ld at time of Coinc Pk	2007	1,201.76	527.69	154.28	266.99	121.30	121.16	10.34
	2008	1,211.99	536.06	155.00	266.83	121.49	122.26	10.34

		Downtown Network				
		Total	Residential	Small	Medium	Large
Peak Load	2007	Dec WD HLH				
	2008	Dec WD HLH				
Ld at time of Coinc Pk	2007	197.41	12.52	23.07	69.93	91.89
	2008	198.26	12.72	23.20	70.38	91.96

Capital & O&M Costs, $2004 / MW	
Capital Cost/MW = $ 8,975.67	O&M Cost/MW = $ 520.48

Cost Adjustments:	$ 2007 = 1.08485	$ 2008 = 1.11414

2007	Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)						
	Total	Residential	Small	Medium	Large	High Demand	Lights
Capital cost	$ 10,786,602	$ 4,736,339	$ 1,384,723	$ 2,396,428	$ 1,088,745	$ 1,087,526	$ 92,842
O&M cost	$ 625,488	$ 274,648	$ 80,297	$ 138,963	$ 63,134	$ 63,063	$ 5,384
Total cost	$ 11,412,090	$ 5,010,987	$ 1,465,019	$ 2,535,391	$ 1,151,879	$ 1,150,588	$ 98,226
Total Cost, $2007	$ 12,380,421	$ 5,436,176	$ 1,589,328	$ 2,750,522	$ 1,249,617	$ 1,248,217	$ 106,560
Share of Svc Terr.	85.891%	37.714%	11.026%	19.082%	8.669%	8.660%	0.739%

2007	Downtown Network					Total Svc Terr. Nonnet+Net
	Total	Residential	Small	Medium	Large	
Capital cost	$ 1,771,892	$ 112,359	$ 207,032	$ 627,692	$ 824,809	$ 12,558,494
O&M cost	$ 102,748	$ 6,515	$ 12,005	$ 36,398	$ 47,829	$ 728,235
Total cost	$ 1,874,639	$ 118,874	$ 219,037	$ 664,090	$ 872,637	$ 13,286,729
Total Cost, $2007	$ 2,033,705	$ 128,961	$ 237,623	$ 720,439	$ 946,682	$ 14,414,126
Share of Svc Terr.	14.109%	0.895%	1.649%	4.998%	6.568%	100.000%

2008	Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)						
	Total	Residential	Small	Medium	Large	High Demand	Lights
Capital cost	$ 10,878,436	$ 4,811,511	$ 1,391,268	$ 2,394,978	$ 1,090,438	$ 1,097,400	$ 92,842
O&M cost	$ 630,813	$ 279,007	$ 80,676	$ 138,879	$ 63,232	$ 63,635	$ 5,384
Total cost	$ 11,509,249	$ 5,090,518	$ 1,471,944	$ 2,533,857	$ 1,153,669	$ 1,161,036	$ 98,226
Total Cost, $2008	$ 12,822,941	$ 5,671,561	$ 1,639,955	$ 2,823,077	$ 1,285,352	$ 1,293,559	$ 109,437
Share of Svc Terr.	85.942%	38.012%	10.991%	18.921%	8.615%	8.670%	0.733%

2008	Downtown Network					Total Svc Terr. Nonnet+Net
	Total	Residential	Small	Medium	Large	
Capital cost	$ 1,779,518	$ 114,189	$ 208,273	$ 631,694	$ 825,362	$ 12,657,954
O&M cost	$ 103,190	$ 6,622	$ 12,077	$ 36,630	$ 47,861	$ 734,003
Total cost	$ 1,882,708	$ 120,810	$ 220,350	$ 668,325	$ 873,222	$ 13,391,957
Total Cost, $2008	$ 2,097,605	$ 134,600	$ 245,502	$ 744,609	$ 972,894	$ 14,920,546
Share of Svc Terr.	14.058%	0.902%	1.645%	4.990%	6.520%	100.000%

	Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)						
	Total	Residential	Small	Medium	Large	High Demand	Lights
2007+'08	$ 25,203,362	$ 11,107,737	$ 3,229,283	$ 5,573,599	$ 2,534,969	$ 2,541,776	$ 215,998
Share of Svc Terr.	85.917%	37.866%	11.008%	19.000%	8.642%	8.665%	0.736%

	Downtown Network					Total Svc Terr. Nonnet+Net
	Total	Residential	Small	Medium	Large	
2007+'08	$ 4,131,309	$ 263,561	$ 483,124	$ 1,465,048	$ 1,919,576	$ 29,334,672
Share of Svc Terr.	14.083%	0.898%	1.647%	4.994%	6.544%	100.000%

neighborhoods). Engineering estimates and costs were developed for this project. That information is the source of capital cost estimates for a nonnetwork substation.

The cost for the substation, including labor, material and contingency, was estimated by the department's engineers to be $14,091,281 in $2004. This cost, though, excluded necessary fiber-optic communication equipment and a SCADA system (system control and data analysis system). This particular design included gas-insulated transformers which increases the total, basic, cost by 25-30 per cent over a substation with 'standard' air-cooled transformers. Using a cost-increase factor of 30 per cent and rounding the result indicates a 'standard' substation with air-cooled transformers would cost about $10,840,000. The fiber optics communication equipment is estimated by the engineers to cost about $500,000. A SCADA system is estimated by the engineers to cost about $250,000. The total capital cost, then, for a standard nonnetwork substation equals $11,590,000. Dividing this cost by the 120 MW of capacity indicates that the capital cost for a nonnetwork substation equals $96,583 / MW.

Table 4.2 in Chapter 2 indicated that substations are expected to have a service life of about 32 years. Using the annualization factor for that life from Chapter 4 indicates the annual capital cost for a nonnetwork substation equals $4,667.59 / MW.[14] Adjusting those costs for losses at 1.56 percent gives an **annual capital cost adjusted for losses of $4,741.56/MW**.[15]

The department's engineers estimate that a substation that serves network customers most likely would require placing the substation in a smaller area because of local, densely packed, contiguous buildings. Cost increases are associated with placing transformers and related equipment in more cramped quarters. The department's engineers' estimates are that a network substation would cost 25 to 50 percent more than a corresponding nonnetwork substation. The engineers agreed that using the rounded, initial total cost of the InterBay substation would be a reasonable estimate for a substation serving network customers. This rounded cost is $14,100,000. As for the nonnetwork substation, this cost excludes necessary fiber-optics and SCADA system. Costs for these items would be the same as for the nonnetwork substation. Total cost for a 120 MW network substation, then, equals $14,850,000. Capital cost per MW equals $123,750.[16] The annual capital cost for a network substation equals $5,980.48 / MW.[17] **The annual capital cost for a network substation, adjusted for losses, equals $6,075.25**.[18]

7.3.2 Operations and Maintenance Costs: Substations

Table 7.4 presents data on the annual O&M costs associated with the system's substations. Rather than relating all the individual FERC accounts, sums of data by ranges of accounts associated with specific functions are reported. As before, the rate-case analysis began when only 2004 data were available, and those are the data used here,

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[14] Annual cost for a 32 year asset with the indicated total capital cost = 0.0483271 * 96,583.33 = 4,667.59.
[15] Annual cost adjusted for losses = 4,667.59 / (1-0.0156) = 4,741.56.
[16] Cost per MW = 14,850,000 / 120 = 123,750.
[17] Annual cost for a network substation = 0.0483271 * 123,750 = 5,980.48.
[18] Losses are 1.56 %, so annual cost adjusted for losses = 5,980.48 / (1-0.0156) = 6,075.25.

but the now available 2005 data are shown for comparison. There is not a great deal of difference between the data from the two years.

Table 7.4
Substation O& M Costs

Item		FERC accounts from	to		2004		2005
1	Load Dispatching	58100	58199	$	1,799,844	$	1,724,860
2	Station Operation	58200	58299	$	2,995,586	$	2,978,894
	Maintenance of Station Equipment(*)	59200	59299	$	1,819,933	$	1,506,006
	(*) needs to be adjusted for age	Base Factor			1.66741		1.69767
	age adjustment factor	=1/(Base Factor)			0.673		0.673
3	Maintenance of Station Equipment Adj. For Age			$	1,224,815	$	1,013,542
4	Station building O&M	59100	59199	$	1,076,734	$	1,239,888
	Total (1 + 2 + 3 + 4)			$	7,096,980	$	6,957,184

One comment is needed about adjusting for age of facilities. The major components of a substation are transformers, capacitor banks and circuit breakers. Most of the Department's transformers are old; two located at the Bothell substation have been changed out in the system, as have three at the South and one at the North substations. Transformers are the most expensive of the major substation components. Approximately half of the high voltage circuit breakers in substations have been replaced. Low voltage breakers have been replaced at Delridge and at University substations. These and other planned replacements increase life expectancy and reduce maintenance of the total substation plant by some small and difficult to define amount.

Since reported O&M expenses covers all substations of all ages, there has been a concern that the average cost per MW derived from these data would not adequately predict the cost for servicing a <u>new</u> marginal substation. The *1989/90 COSACAR* discussed an analysis of labor hours spent on preventative and corrective maintenance which constitute the bulk of substation maintenance work. (See pages 4.31 and 4.32 of that earlier study.) That analysis established a regression relationship between labor costs per MW and age of the substation upon which the maintenance was done. Costs rose with age.

The regression results became an estimate of annual labor costs expected to be incurred for every year the substation was in service. The present value of these costs for 35 years was estimated and the <u>annualized</u> cost, desired for the analysis here, equaled the predicted <u>annual</u> cost at age 14. At the time of that study, the average age of the substations was 26.5 years. A ratio of the regression predicted costs for the ages of 26.5 and 14 years was estimated to be 1.3731.[19] The reported expenses were then adjusted by the reciprocal of this number.

At the time of the *1993/94 COSACAR*, the average age of substations had advanced by four years.[20] No account was taken of any of the improvements made to substations in

[19] Page 4.31a of the *1989/90 COSACAR* presents a graph of the regression results. The ratio of the value of 26.5 years and 14 years equal 1.37.

[20] Major rehabilitation projects that will essentially renew several substations will be developed over the next several years. That rehabilitation will retard the increase in average age of substations. No major

the intervening time. By using the same regression analysis results from the *1989/90 COSACAR*, a value of 1.485 for the ratio of labor costs for a plant age 30.5 years and a 14 year old plant was obtained. The reciprocal of this value is 0.673 which was used to adjust maintenance of station equipment costs in the 1995/96 *COSACAR*.

For purposes of this *2007/2008 COSACAR*, it is still important to recognize that maintenance costs for the existing system of substations may not reflect the annualized costs of a marginal, *new* substation. But it is also difficult to develop a precise correction factor for adjusting the costs of the existing system to reflect the costs of maintaining a new substation. The *2000/2002 COSACAR* faced the same issue. Discussion with a senior engineer in Power System & Substation Engineering at the time of the *2000/2002 COSACAR* led to an agreement to use the adjustment factor from the *1993/94 COSACAR*, again (as was done in the *1995/96 and 1997/98 COSACARs*), to adjust current maintenance costs for age. Recent discussions with senior engineers lead to the same conclusion. Substations have desired schedules for regular replacement and upgrading of major equipment. However, sometimes budget constraints require postponement of some of this work. The adjustment factor of 0.673 acknowledges that some adjustments must be made to reported costs, that the adjustment has become larger since the research was done for the *1989/90 COSACAR*, but also acknowledges that some life-enhancing improvements to the existing substations have been undertaken since that *1989/90 COSACAR* research project. Table 7.4, therefore, uses this factor with the reported maintenance of station equipment costs to adjust for differences in costs that could be expected for a system composed of all new equipment.[21]

7.3.3 Derivation of Cost Shares: Substations

Cost shares for substation revenue requirements by class for the nonnetwork and network classes are developed in **Table 7.5** on the next page. As with the development of cost shares for in-service area transmission, these cost calculations begin with the load of each class at the time of the system peak load that come from Table 5.6 in Chapter 5. Those loads are multiplied by the capital cost and O&M cost per MW. The sum of these costs is computed, then converted to dollars of the forecast year. The service territory total of costs over all classes is computed and shares by class of this total cost are computed. Shares used to allocate the sum of revenue requirements for 2007 and 2008 are derived by adding the total marginal costs for each those years and dividing by the sum of costs for the total service territory.

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rehabilitations have occurred in the period of time between the study referred to in the *1989/90 COSACAR* and 1991, the date of the current information, hence the average age of substations increased by the number of years between these two studies.

[21] Engineers anticipate that future substations will utilize a more advanced technology of gas-insulated transformers which will have a higher capital cost than current air-cooled transformers, but require much less square-footage of space (one-sixth as much) and have substantially less maintenance costs. This technology and its associated costs should be examined in the next rate case to determine whether at that time it is, perhaps, more appropriate than the costs for current technology equipment.

Table 7.5
Derivation of Cost Shares for Substations

Coincident Loads, Loads at Time of System Peak Demand

		Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)						
		Total	Residential	Small	Medium	Large	High Demand	Lights
Period of Peak Load	2007	Dec WD HLH						
	2008	Dec WD HLH						
Ld at time of Coinc Pk	2007	1,201.76	527.69	154.28	266.99	121.30	121.16	10.34
	2008	1,211.99	536.06	155.00	266.83	121.49	122.26	10.34

Nonnetwork Capital & O&M Costs, $2004 / MW

Capital Cost/MW = $ 4,741.56 O&M Cost/MW = $ 2,887.30

		Downtown Network				
		Total	Residential	Small	Medium	Large
Peak Load	2007	Dec WD HLH				
	2008	Dec WD HLH				
Ld at time of Coinc Pk	2007	197.41	12.52	23.07	69.93	91.89
	2008	198.26	12.72	23.20	70.38	91.96

Network Capital & O&M Costs, $2004 / MW

Capital Cost/MW = $ 6,075.25 O&M Cost/MW = $ 2,887.30

Cost Adjustments: $ 2007 = 1.08485 $ 2008 = 1.11414

	Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)						
2007	Total	Residential	Small	Medium	Large	High Demand	Lights
Capital cost	$ 5,698,219	$ 2,502,057	$ 731,505	$ 1,265,957	$ 575,149	$ 574,505	$ 49,046
O&M cost	$ 3,469,842	$ 1,523,589	$ 445,439	$ 770,885	$ 350,228	$ 349,836	$ 29,866
Total cost	$ 9,168,061	$ 4,025,646	$ 1,176,944	$ 2,036,841	$ 925,378	$ 924,341	$ 78,911
Total Cost, $2007	$ 9,945,983	$ 4,367,227	$ 1,276,809	$ 2,209,670	$ 1,003,897	$ 1,002,773	$ 85,607
Share of Svc Terr.	83.823%	36.806%	10.761%	18.623%	8.461%	8.451%	0.721%

	Downtown Network					Total Svc Terr.
2007	Total	Residential	Small	Medium	Large	Nonnet+Net
Capital cost	$ 1,199,318	$ 76,051	$ 140,131	$ 424,858	$ 558,278	$ 6,897,537
O&M cost	$ 569,983	$ 36,144	$ 66,598	$ 201,917	$ 265,325	$ 4,039,826
Total cost	$ 1,769,302	$ 112,195	$ 206,729	$ 626,775	$ 823,603	$ 10,937,363
Total Cost, $2007	$ 1,919,429	$ 121,715	$ 224,270	$ 679,957	$ 893,487	$ 11,865,412
Share of Svc Terr.	16.177%	1.026%	1.890%	5.731%	7.530%	100.000%

	Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)						
2008	Total	Residential	Small	Medium	Large	High Demand	Lights
Capital cost	$ 5,746,731	$ 2,541,768	$ 734,962	$ 1,265,191	$ 576,043	$ 579,722	$ 49,046
O&M cost	$ 3,499,384	$ 1,547,770	$ 447,544	$ 770,418	$ 350,773	$ 353,013	$ 29,866
Total cost	$ 9,246,115	$ 4,089,538	$ 1,182,506	$ 2,035,609	$ 926,816	$ 932,734	$ 78,911
Total Cost, $2008	$ 10,301,488	$ 4,556,328	$ 1,317,480	$ 2,267,958	$ 1,032,605	$ 1,039,199	$ 87,918
Share of Svc Terr.	83.880%	37.100%	10.728%	18.467%	8.408%	8.462%	0.716%

	Downtown Network					Total Svc Terr.
2008	Total	Residential	Small	Medium	Large	Nonnet+Net
Capital cost	$ 1,204,481	$ 77,290	$ 140,971	$ 427,567	$ 558,652	$ 6,951,212
O&M cost	$ 572,437	$ 36,732	$ 66,997	$ 203,204	$ 265,503	$ 4,071,820
Total cost	$ 1,776,917	$ 114,022	$ 207,969	$ 630,771	$ 824,155	$ 11,023,032
Total Cost, $2008	$ 1,979,739	$ 127,037	$ 231,707	$ 702,769	$ 918,226	$ 12,281,226
Share of Svc Terr.	16.120%	1.034%	1.887%	5.722%	7.477%	100.000%

	Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)						
	Total	Residential	Small	Medium	Large	High Demand	Lights
2007+'08	$ 20,247,471	$ 8,923,555	$ 2,594,289	$ 4,477,628	$ 2,036,502	$ 2,041,971	$ 173,525
Share of Svc Terr.	83.852%	36.956%	10.744%	18.543%	8.434%	8.457%	0.719%

	Downtown Network					Total Svc Terr.
	Total	Residential	Small	Medium	Large	Nonnet+Net
2007+'08	$ 3,899,168	$ 248,751	$ 455,977	$ 1,382,726	$ 1,811,713	$ 24,146,639
Share of Svc Terr.	16.148%	1.030%	1.888%	5.726%	7.503%	100.000%

7.4 Wires and Related Equipment

Wires and related equipment are used to transport or facilitate transport of power over 26 kV lines (or 27 MW for nonnetwork customers) or 13 kV lines (for network customers) from substations to near the location of retail consumers. At that point near the customer, the power is put through a final transformer (the customer transformer) and fed through a service drop to a meter and then to the customer. The next two sections discuss costs for meters and customer transformers. This section discusses the costs of the wires and related equipment as well as the customer service drop.

Revenue requirements associated with these items are assigned, at the stage of the functionalization of revenue requirements, separately to nonnetwork and network customers. Cost shares, therefore, are developed separately for nonnetwork and network customers.

7.4.1 Capital Costs: Nonnetwork: Wires and Related Equipment

Table 7.6 presents a listing of the wires and related equipment associated with distributing power over the nonnetwork portion of the system. Total $2005 capital cost equals $1.7225 billion. This equipment serves 160 feeders of 27 MW each, or a total capacity of 4,320 MW. Thus the capital cost per MW equals $398,727. The expected lifetime for this equipment is 45 years. Using the annualization factor for 45 years with a half-year shift from the text in chapter 4, the annual cost for this equipment equals $16,023.57. Adjusting this for line losses from Table 5.7 (0.82%) indicates the adjusted **$2005 capital cost per MW of load for nonnetwork wires and related equipment is $16,156.**

Table 7.6
Nonnetwork Wires and Related Equipment Capital Cost, $2005

Item name	Unit Labor Cost ($)	Unit Material Cost ($)	Labor & Material Cost ($)	System Qunatity	Total Cost ($)
anchor	140	60	200	19,117	3,823,400
pipe brace anchor	339	145	484	5,713	2,765,092
sectionalizers	1,297	856	2,153	202	434,906
600 amp OH switch	2,040	4,042	6,082	1,816	11,044,912
1200 amp OH switch	2,040	7,134	9,174	324	2,972,376
Capacitor	3,269	6,916	10,185	46	468,510
Cutouts	1,297	556	1,853	6,381	11,823,993
Cutouts with limiters	1,297	756	2,053	1,224	2,512,872
< 25' pole	656	425	1,081	506	546,986
30-35' pole	656	488	1,144	14,477	16,561,688
36-40' pole	656	597	1,253	11,479	14,383,187
41-45' pole	656	778	1,434	18,100	25,955,400
46-50' pole	656	778	1,434	20,624	29,574,816
51-55' pole	656	924	1,580	6,453	10,195,740
56-60' pole	820	1,087	1,907	3,082	5,877,374
61-70' pole	820	1,628	2,448	1,889	4,624,272
71-80' pole	820	1,778	2,598	776	2,016,048
#4 bare copper wire/ft, 1 phase	2	1	3	4,209,727	11,829,333
#4 bare copper wire/ft, 3 phase	6	3	8	1,668,716	14,134,025
397 ACSR, 3 phase, 600 amp	9	4	13	2,945,519	37,791,009
954 ACSR, 3 phase, 1200 amp	26	11	37	461,669	17,169,470
954 ACSR, 34 kV	26	12	38	19,440	742,414
1/0 triplex; inc open 2-#2 & 1-#4	2	1	3	5,563,318	17,969,517
1/0 quadplex	4	2	6	289,248	1,758,628
1/0 27 kV UG inc duct, trench, vaul	56	294	350	2,087,306	730,557,100
1000 kCM UG inc duct, trench & V	282	368	650	468,141	304,291,650
2-1000kCM UG inc duct, trench &V	423	552	975	100,331	97,822,725
Handholes, ave 233 & 444	1,890	925	2,815	9,289	26,148,535
Manholes, 712	11,510	7,124	18,634	162	3,018,708
Vaults, ave, 577, 612, 814 & 818	13,336	8,282	21,618	7,424	160,492,032
Pads, ave	1,679	500	2,179	993	2,163,747
PMH5 switch	26,107	17,398	43,505	23	1,000,615
PMH5 E switch	28,107	25,900	54,007	25	1,350,175
PMH 9 switch	24,598	18,404	43,002	88	3,784,176
PMH10 switch	25,663	15,946	41,609	35	1,456,315
PMH12 switch	22,528	15,591	38,119	64	2,439,616
UG terminations, ave	3,101	2,403	5,504	3,191	17,563,264
J Boxes, ave	7,976	2,474	10,450	11,812	123,435,400
Total			330,589	17,958,730	1,722,500,025

7.4.2 Capital Costs: Network: Wires and Related Equipment

Table 7.7 on the next page presents a listing of the wires and related equipment associated with distributing power through the network portion of the system. Total $2005 capital costs equal $1.6904 billion, i.e., not significantly less than for the

Table 7.7
Network Wires and Related Equipment Capital Cost, $2005

	Number/ Feet	Unit Matl Cost	Total Matl Cost	Unit Labor	Total Labor Cost	Unit Engrg	Total Engrg	Mics./Unit	Replacement Cost
Manhole and Vaults	1470	$24,000	$35,280,000	$450,000.00	$661,500,000	$35,000	$51,450,000	$240,000	$1,101,030,000
U Distr MH	120	$19,000	$2,280,000	$405,000	$48,600,000	$35,000	$4,200,000	$240,000	$83,880,000
U Distr Vaults	64	$26,000	$1,664,000	$450,000.00	$28,800,000	$35,000	$2,240,000	$240,000	$48,064,000
U Distr Handholes	80	$780	$62,400	$8,480	$678,400	$648	$51,856	$3,000	$1,032,656
Handholes	515	$780	$401,700	$8,480	$4,367,200	$648	$333,823	$3,000	$6,647,723
duct banks	362531	$26	$9,425,806	$500	$181,265,500	$37	$13,348,391	$339	$326,782,336
Primary Cable	884953	$47.30	$41,858,276.90	$33.89	$29,990,317	$6	$5,029,402		$76,877,996
Secondary Cable	539182	$31.20	$16,822,478.40	$27.56	$14,859,856	$4	$2,217,763		$33,900,098
Limiters	10800	$58	$626,400.00	$29	$309,096	$6	$65,485		$1,000,981
Secndry Buses	1358	$1,500	$2,037,000	$77	$105,082.04	$110	$149,946		$2,292,028
BTS	122	$28,000	$3,416,000	$6,886	$840,062.72	$2,442	$297,924		$4,553,987
Fire Protection System	322	$6,000	$1,932,000	$6,530	$2,102,531	$877	$282,417		$4,316,948
Total									$1,690,378,752

nonnetwork system. The network distribution system has a capacity of 660 MW at unitary power factor. Therefore the capital cost per MW equals $2,561,180. The various kinds of equipment have expected lives ranging from 15 to 100 years. The modal expected life is estimated to be 30 years. Using the annualization factor for this lifetime, the annual capital cost for network wires and related equipment equals $128,752.49 per MW. Adjusting this for losses through feeders (0.82%) gives a **$2005 adjusted annual capital cost for network wires, etc., of $129,816.99 per MW.**

7.4.3 Annual Operations and Maintenance Cost , Nonnetwork: Wires and Related Equipment

Table 7.8 presents the annual O&M costs for nonnetwork service in 2004, which is used in the analysis here, and 2005, which became available later. The network costs

Table 7.8
Nonnetwork Operations and Maintenance Costs

Nonnetwork Distribution O&M	**FERC #**	**2004**	**2005**
Use 100% of Costs			
INSP TEST & PATROL OH DIST LIN	58352	274,336	180,258
OH LINE ENGR EXP	58359	86,616	44,619
CLEAR TREES & TRIM BRUSH OH LI	59350	2,257,172	2,770,049
MAINT POLES CONDCTRS & SERVICE	59352	4,308,464	4,044,526
MAINT OH DIST SYSTEM EQUIP	59353	4,879	-
MAINT OH LINES ENGR	59359	6,547	707
INSP & TEST UG DIST	58462	799,615	819,358
UG ENGR LINE EXP	58469	51,588	65,068
MAINT NON-ELECT UG EQUIP	59460	628,565	826,724
MAINT ELECT UG EQUIP	59462	1,755,746	1,913,116
	Subtotal	10,173,528	10,664,425
Use 15.1% of costs …. These are network costs outside the downtown network that need to be added to nonnetwork costs,			
INSPECT & TEST NETWORK UG DIST	58442	258,189	228,092
MAINT NETWORK UG LINES	59440	693,098	373,946
MAINT NETWORK UG EQUIP	59442	735,084	935,701
MISC NETWK UG DIST SYS EXP	58841	146,103	137,166
	Subtotal	1,832,474	1,674,906
	15.1% of Subtotal	276,704	252,911
Total Nonnetwork Rate Classes O&M expenses		**10,450,232**	10,917,336

discussed in the next subsection pertain to only the downtown network area. There are two smaller network areas that have different characteristics than the downtown network so that they are excluded from network rates. Their O&M costs, however, are combined in the accounting records with the costs of the downtown network. The downtown network load comprised 84.9 percent of total network load in 2003. Thus the remainder of the total network comprised 15.1 percent of the total load. We use the latter figure to estimate the 'nonnetwork' portion of costs recorded as network in Table 7.7. Thus there are two portions of Table 7.7. The top portion pertains to costs that clearly are associated with nonnetwork service. The bottom portion lists costs that are labeled as 'network' but only 15.1 percent of those costs are used as 'nonnetwork' costs for purposes of analysis here. Total O&M costs for 2004, therefore, equal $10,450,232. Dividing this total cost by the 4,320 MW capacity of the nonnetwork system produces an **annual $2004 O&M cost of $2,419/MW**.

7.4.4 Annual Operations and Maintenance Cost: Network: Wires and Related Equipment

Table 7.9 presents the annual O&M costs for network service in 2004, which is used in the analysis here, and 2005, which became available later. As mentioned above, cost data for the downtown network are combined with costs for two smaller, and different, network areas on First Hill and in the University District. Load in the downtown network accounted for 84.9 percent of the total of all network loads in 2003 so the cost data were adjusted by that percentage to estimate the annual O&M costs of $1,555,771 for the downtown network. Dividing this total annual cost by the 660 MW capacity of the downtown network produces an **annual $2004 O&M cost of $2,357/MW for network service**.

Table 7.9
Network Operations and Maintenance Costs

Network Distribution O&M Costs	**FERC #**	**2004**	**2005**
Use 84.9% of costs . . . The following are total costs for all networks; the downtown network represented 84.9% of all network load in 2003			
INSPECT & TEST NETWORK UG DIST	58442	258,189	228,092
MAINT NETWORK UG LINES	59440	693,098	373,946
MAINT NETWORK UG EQUIP	59442	735,084	935,701
MISC NETWK UG DIST SYS EXP	58841	146,103	137,166
	Subtotal	1,832,474	1,674,906
Total Network Distribution O&M Costs	**84.9% of Subtotal**	**1,555,771**	1,421,995

7.4.5 Annual Operations and Maintenance Costs: Service Drops

The capital cost of wires that lead from a customer's transformer to the customer are included in the capital costs for nonnetwork and network customers listed above. These wires, though, do receive some maintenance work whose costs need to be added to the O&M costs developed above. These costs are developed in terms of dollars per meter in Chapter 8. See Table 8.26b for the costs per meter. See Table 5.9 in Chapter 5 for source of number of meters. **Table 7.10** shows the derivation of the annual O&M costs for service drops.

Table 7.10
Derivation of Service Drop Annual O&M

Meters	Total Nonnetwork (EXcludes Network Residential & Small)						
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
2007	**370,540**	**328,228**	**39,712**	**2,500**	**89**	**11**	**N/A**
2008	**372,689**	**330,177**	**39,912**	**2,500**	**89**	**11**	**N/A**

Meters	Downtown Network				
	Total	**Residential**	**Small**	**Medium**	**Large**
2007	**16,298**	**12,445**	**3,303**	**493**	**57**
2008	**16,349**	**12,496**	**3,303**	**493**	**57**

	2004$/meter/year					
O&M Cost	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Nonnet	**2.31**	**2.63**	**9.00**	**238.63**	**1,032.56**	**N/A**
Net	**2.31**	**3.02**	**9.00**	**1,260.00**		

Cost Adjustments: **$ 2007 = 1.08485** **$ 2008 = 1.11414**

O&M Cost	Total Nonnetwork (EXcludes Network Residential & Small)						
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
2007	917,745	758,207	104,443	22,500	21,238	11,358	N/A
$2007	995,617	822,542	113,305	24,409	23,040	12,322	
2008	922,774	762,709	104,969	22,500	21,238	11,358	N/A
$2008	1,028,101	849,766	116,950	25,068	23,662	12,655	

	Downtown Network				
	Total	**Residential**	**Small**	**Medium**	**Large**
2007	114,980	28,748	9,975	4,437	71,820
$2007	124,736	31,187	10,821	4,813	77,914
2008	115,098	28,866	9,975	4,437	71,820
$2008	128,235	32,161	11,114	4,943	80,018

7.4.6 Derivation of Cost Shares: Wires and Related Equipment

Cost shares for wires and related equipment revenue requirements by class for the nonnetwork and network classes are developed in **Table 7.11**. As with the development of cost shares for the previous distribution functions, these cost calculations begin with the load of each class at the time of the system peak load that come from Table 5.6 in Chapter 5. Those loads are multiplied by the capital cost and O&M cost per MW. Note, though, that the capital costs in this case are in terms of $2005 and the O&M costs are in terms of $2004. Thus these costs are adjusted to years dollars of the forecast year, first. O&M costs for service drops are added. Their costs come directly from Table 7.10. Then the sum of these costs is computed. As mentioned, revenue requirements are assigned initially to nonnetwork and network customers separately. Thus shares just for nonnetwork and just for network classes are developed. Shares used to allocate the sum of revenue requirements for 2007 and 2008 are derived by adding the total marginal costs for each those years and dividing by the sum of costs for nonnetwork and network as appropriate.

Table 7.11
Derivation of Cost Shares for Wires and Related Equipment

Coincident Loads, Loads at Time of System Peak Demand

		Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)						
		Total	Residential	Small	Medium	Large	High Demand	Lights
Period of	2007	Dec WD HLH						
Peak Load	2008	Dec WD HLH						
Ld at time	2007	1,201.76	527.69	154.28	266.99	121.30	121.16	10.34
of Coinc Pk	2008	1,211.99	536.06	155.00	266.83	121.49	122.26	10.34

Nonnetwork Capital Costs, $2005	O&M Costs, $2004
Capital Cost/MW = $ 16,156.05	O&M Cost/MW = $ 2,419.04

		Downtown Network				
		Total	Residential	Small	Medium	Large
Peak	2007	Dec WD HLH				
Load	2008	Dec WD HLH				
Ld at time	2007	197.41	12.52	23.07	69.93	91.89
of Coinc Pk	2008	198.26	12.72	23.20	70.38	91.96

Network Capital Costs, $2005	O&M Costs, $2004
Capital Cost/MW = $ 129,816.99	O&M Cost/MW = $ 2,357.23

Capital Cost Adjustments:	$ 2007 = 1.05319	$ 2008 = 1.08163
O&M Cost Adjustments:	$ 2007 = 1.08485	$ 2008 = 1.11414

in $2007	Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)						
2007	Total	Residential	Small	Medium	Large	High Demand	Lights
Capital cost	$ 20,448,401	$ 8,978,782	$ 2,625,050	$ 4,542,962	$ 2,063,958	$ 2,061,646	$ 176,003
Wires O&M cost	$ 3,153,778	$ 1,384,807	$ 404,864	$ 700,666	$ 318,326	$ 317,970	$ 27,145
Service Drop O&M cost	$ 995,617	$ 822,542	$ 113,305	$ 24,409	$ 23,040	$ 12,322	$ -
Total cost	$ 24,597,796	$ 11,186,131	$ 3,143,218	$ 5,268,037	$ 2,405,325	$ 2,391,938	$ 203,148
Share of Nonnetwork	100.000%	45.476%	12.778%	21.417%	9.779%	9.724%	0.826%

	Downtown Network				
2007	Total	Residential	Small	Medium	Large
Capital cost	$ 26,990,328	$ 1,711,508	$ 3,153,609	$ 9,561,318	$ 12,563,893
O&M cost	$ 504,827	$ 32,012	$ 58,985	$ 178,835	$ 234,995
Service Drop O&M cost	$ 124,736	$ 31,187	$ 10,821	$ 4,813	$ 77,914
Total cost	$ 27,619,891	$ 1,774,707	$ 3,223,416	$ 9,744,966	$ 12,876,802
Share of Network	100.000%	6.425%	11.671%	35.282%	46.621%

in $2008	Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)						
2008	Total	Residential	Small	Medium	Large	High Demand	Lights
Capital cost	$ 21,179,299	$ 9,367,562	$ 2,708,668	$ 4,662,798	$ 2,122,980	$ 2,136,536	$ 180,755
O&M cost	$ 3,266,505	$ 1,444,769	$ 417,761	$ 719,148	$ 327,429	$ 329,520	$ 27,878
Service Drop O&M cost	$ 1,028,101	$ 849,766	$ 116,950	$ 25,068	$ 23,662	$ 12,655	$ -
Total cost	$ 25,473,905	$ 11,662,097	$ 3,243,379	$ 5,407,015	$ 2,474,072	$ 2,478,711	$ 208,633
Share of Nonnetwork	100.000%	45.781%	12.732%	21.226%	9.712%	9.730%	0.819%

	Downtown Network				
2008	Total	Residential	Small	Medium	Large
Capital cost	$ 27,838,377	$ 1,786,346	$ 3,258,178	$ 9,882,081	$ 12,911,772
O&M cost	$ 520,689	$ 33,412	$ 60,941	$ 184,834	$ 241,502
Service Drop O&M cost	$ 128,235	$ 32,161	$ 11,114	$ 4,943	$ 80,018
Total cost	$ 28,487,302	$ 1,851,918	$ 3,330,233	$ 10,071,859	$ 13,233,291
Share of Network	100.000%	6.501%	11.690%	35.356%	46.453%

	Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)						
	Total	Residential	Small	Medium	Large	High Demand	Lights
2007+'08	$ 50,071,702	$ 22,848,227	$ 6,386,597	$ 10,675,051	$ 4,879,396	$ 4,870,649	$ 411,781
Share of Svc Terr.	100.000%	45.631%	12.755%	21.320%	9.745%	9.727%	0.822%

	Downtown Network				
	Total	Residential	Small	Medium	Large
2007+'08	$ 56,107,193	$ 3,626,626	$ 6,553,648	$ 19,816,825	$ 26,110,093
Share of Svc Terr.	100.000%	6.464%	11.681%	35.320%	46.536%

7.5 Meters (Excluding Meter Reading) Derivation of Cost Shares

Chapter 8 develops costs associated with customers, including meters. Table 8.27b presents a summary of meter costs. That table also includes costs on service drop maintenance presented in Table 8.26b that have already been included in the annual O&M costs for service drops displayed in Table 7.10. Thus the meter costs desired here equal the total costs from Table 8.27b LESS the costs indicated for Service Maintenance. **Table 7.12** uses these costs in the derivation of cost shares used to allocate meter revenue requirements. Those costs include both capital and O&M costs. They are expressed in dollars per meter. As before, the meter forecast comes from Table 5.9 in Chapter 5. Shares used to allocate the sum of revenue requirements for 2007 and 2008 are derived by adding the total marginal costs for each those years and dividing by the sum of costs for the total service territory.

Table 7.12
Derivation of Cost Shares for Meters

	Total Nonnetwork (EXcludes Network Residential & Small)						
Meters	Total	Residential	Small	Medium	Large	High Demand	Lights
2007	370,540	328,228	39,712	2,500	89	11	N/A
2008	372,689	330,177	39,912	2,500	89	11	N/A

	Downtown Network				
Meters	Total	Residential	Small	Medium	Large
2007	16,298	12,445	3,303	493	57
2008	16,349	12,496	3,303	493	57

	2004$/meter/year					
Capital + O&M Cost	Residential	Small	Medium	Large	High Demand	Lights
Nonnet	5.24	13.88	71.64	133.69	591.20	N/A
Net	12.58	17.55	50.36	107.14		

Cost Adjustments:	$ 2007 = 1.08485	$ 2008 = 1.11414

Capital + O&M Cost	Total Nonnetwork (EXcludes Network Residential & Small)						
	Total	Residential	Small	Medium	Large	High Demand	Lights
2007	2,468,619	1,719,915	551,203	179,100	11,898	6,503	N/A
$2007	2,678,084	1,865,852	597,973	194,297	12,908	7,055	
Share of Svc Terr.	90.956%	63.370%	20.309%	6.599%	0.438%	0.240%	0.000%

	Downtown Network					Svc Terr Total
	Total	Residential	Small	Medium	Large	
2007	245,460	156,558	57,968	24,827	6,107	2,714,079
$2007	266,288	169,842	62,886	26,934	6,625	2,944,372
Share of Svc Terr.	9.044%	5.768%	2.136%	0.915%	0.225%	100.000%

	Total Nonnetwork (EXcludes Network Residential & Small)						
	Total	Residential	Small	Medium	Large	High Demand	Lights
2008	2,481,608	1,730,127	553,979	179,100	11,898	6,503	N/A
$2008	2,764,864	1,927,608	617,211	199,543	13,257	7,245	
Share of Svc Terr.	90.978%	63.428%	20.309%	6.566%	0.436%	0.238%	0.000%

	Downtown Network					Svc Terr Total
	Total	Residential	Small	Medium	Large	
2008	246,102	157,200	57,968	24,827	6,107	2,727,709
$2008	274,192	175,143	64,584	27,661	6,804	3,039,057
Share of Svc Terr.	9.022%	5.763%	2.125%	0.910%	0.224%	100.000%

	Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)						
	Total	Residential	Small	Medium	Large	High Demand	Lights
2007+'08	$ 5,442,949	$ 3,793,460	$ 1,215,184	$ 393,840	$ 26,165	$ 14,300	N/A
Share of Svc Terr.	90.967%	63.399%	20.309%	6.582%	0.437%	0.239%	0.000%

	Downtown Network					Total Svc Terr. Nonnet+Net
	Total	Residential	Small	Medium	Large	
2007+'08	$ 540,480	$ 344,985	$ 127,470	$ 54,595	$ 13,429	$ 5,983,429
Share of Svc Terr.	9.033%	5.766%	2.130%	0.912%	0.224%	100.000%

7.6 Customer Transformers

7.6.1 General Discussion of Transformers

Transformers near the customer are used to convert voltage on feeder lines (13 or 26 kV) to a lower voltage the customer will use directly. These transformers must be sized to carry the maximum demand placed on them. For larger customers, each customer has one (or more) transformers -- the transformers are not shared with other customers. For smaller customers, several customers will share one transformer.

7.6.2 The Problem of Many Types of Transformers

One problem in a marginal cost study is that there is not just one type of transformer that is used for all customers. Pole-mount, pad-mount, submersible, and network are some of the different types of transformers used on the City Light system, and each of these types comes in different sizes at different unit costs.

Conceptually, this problem of multiple transformer types could be solved either by selecting a typical transformer for each class and proceeding with the analysis of its costs, or by taking the composite cost of all the types of transformers used in a particular class. In this cost study, both approaches have been employed. For the Residential and Small General Service classes, a typical transformer has been used in the analysis.

For the Medium, Large General Service and High Demand classes, where the presence of economies-of-scale and network service complicate the picture, a more refined analysis, developed and used since the *1989/90 COSACAR* has been used here. The number of transformers in each size category needed to serve each individual customer was estimated based on engineering design guidelines the Department would use if it were setting up the service for the first time and each customer's maximum recorded demand in 2005. The "frequencies" of each transformer size appear in column (D) of tables 7.19 through 7.21. Averages of recent transformer purchase prices and current installed labor costs associated with each transformer have been summed over all the transformers used in the class to produce a total cost for the class. This total cost is converted to unit costs for the class by dividing by the class noncoincidental maximum demand.

Some costs that would normally be part of an <u>average</u> cost study are excluded or, at least, measured differently in this analysis of <u>marginal</u> transformer costs. The purchase cost used to calculate the marginal cost of a transformer is the approximate current replacement price, not the original purchase price. The marginal installation cost of setting a transformer is based on <u>current</u> labor costs, not the cost of labor when transformers already in service were actually installed. In other words, it is not actual historical costs that determine marginal costs but rather, the costs of <u>adding</u> new transformers to the system.

There are a number of loaded costs (loadings) associated with transformers. Some of the loadings reflect variable costs, but others are more representative of fixed costs. Since by definition, fixed costs do not change when a marginal unit is added, they should be excluded from the calculation of marginal cost. The loadings for labor, transportation, and exempt materials represent variable costs of setting transformers and are included in the analysis. However, the administrative and general (A&G) and materials handling loadings are more on the fixed cost side of the spectrum. A&G costs would likely be unaffected by a marginal increase in transformer installations. Classifying the materials handling loading as a fixed cost is less clear-cut. This loading primarily represents the labor costs in the warehouse of stocking the transformer, handling it, and loading it up for transport to the site. The implicit assumption is that there are sufficient labor resources at the warehouses to absorb a marginal increase in workload without adding new employees or increasing overtime.

The basic design rule used in the selection of a transformer for a particular customer is to match the transformer rating with the customer's maximum demand. Since transformers come in discrete sizes, the rule is that the transformer must be at least as large as the customer's maximum demand. In general, then, there will always be more transformation capability than the amount required to meet the maximum demand of customers.

An exception to this rule occurs for residential transformers. Ambient temperature affects the loading of transformers. Since residential customers typically reach their maximum demand in the winter, often on the coldest day of the year, residential transformers are undersized. The expected maximum demand on residential transformers typically exceeds the transformer ratings by 50%. This is possible because the load capability of the transformers rises as ambient temperature falls. On very cold days, the actual capacity of the transformer can be half again or more as great as its nameplate rating. Therefore, residential transformers can be sized taking both peak demand and expected temperatures at peak into account.

In the network area, redundant transformer capacity is installed to increase the reliability of service and to permit maintenance work without service interruption. Network customers are fed by more than one distribution line. As a result, a break in one feeder does not result in loss of service (as is the case in non-network areas) as long as sufficient transformer capacity exists to carry the load. In a typical network configuration, three lines are brought to three transformers sized such that service can be maintained with any two of the three lines in service. By loading three transformers in a vault to 67% (i.e. 2/3) capacity each, if one goes out the remaining two will still be able to carry the entire load, with their loading going up to about 100% of their rating. Similarly, banks of four transformers are loaded to 75% so that if one fails, the load will not exceed 100% of the rating for the other three. This "N-1 rule" is followed for the network transformer assignments made in this study[22]. In other words, this analysis assumes that the number of transformers needed to carry the load in the network areas is augmented by one in order to provide increased reliability. If multiple banks of two or three transformers are needed to handle a customer's load, each bank will be augmented by a similar transformer to make banks of three or four similar-size transformers.

[22] Smaller network customers were assigned using this "N-1" capacity approach, but were assigned fictitious transformer capacities and converted to the minimum network size of 500 kVA.

7.6.3 Transformer Costs and Cost-Related Factors

Calculation of transformer costs, estimation of the noncoincident maximum demand (connected load) for the test year, and application of the unit costs to the connected loads by class are required to determine each classes' share of total marginal cost of transformation services. The cost categories and related factors discussed separately below, are capital costs, O&M costs, load factors, and losses. The last column of **Table 7.13** displays the total annual cost per kW of providing transformation services to each of the customer classes. Actual calculations of transformer costs by customer class are summarized in Tables 7.17 through 7.21.

A specialized analysis was performed for network and nonnetwork customers. Several of the tables in this chapter present data for consolidated classes, i.e., for nonnetwork and network customers combined, as well as for network and nonnetwork customers considered separately. . The detailed information on network and nonnetwork customers are used in the basic analysis for this rate case

Table 7.13
Annual Capital & Total Cost of Transformers, $2005

	Annual MWH	Connected Load* (MW)	Levelized Capital Cost# ($/kW/Yr)	Total Annual Capital Cost	Total Levelized Cost## ($/kW/Yr)
Residential	3,040,416	908.4	$3.08	$2,798,261	$3.08
Small	1,162,324	345.0	$3.12	$1,075,092	$3.12
Medium, Combined	2,297,475	621.1	$33.36	$20,717,310	$11.75
Medium, Nonnetwk	1,705,925	510.0	$33.36	$17,013,413	$4.61
Medium, Network	591,551	111.0	$33.36	$3,703,897	$35.06
Large, Combined	1,362,279	356.8	$8.36	$2,984,897	$8.79
Large, Nonnetwk	734,699	200.4	$3.13	$627,458	$3.29
Large, Network	627,579	156.5	$15.10	$2,362,223	$15.87
High Demand	1,042,232	257.8	$2.06	$530,937	$2.16
Streetlights	94,855	20.7	$3.12	$64,424	$3.12
TOTAL	12,659,334	3,487.6		$51,877,912	

* i.e., Total Noncoincident Maximum Demand by class from Table 7.17
# Levelized Capital Cost Adjusted for Losses. See Tables 7.19 - 7.23
Levelized Capital Cost Adjusted for Losses + Share of Annual O&M Cost.
See Tables 7.19 - 7.23

7.6.4 Capital Costs: Transformers

The capital costs of transformers include the current purchase price of the transformer and associated equipment and materials, the labor to set the transformer, an allotment for inventory reserves, and an adjustment for losses through the transformer. The purchase prices used in this analysis are averages of recent actual purchases, usually from 2004. The purchase price for each size and type of transformer, network protector and ancillary equipment, including sales tax, is shown in Table 7.14. The labor to install the transformer includes only the cost of setting the transformer, testing it, installing related equipment when needed (such as network protectors, disconnect switches, etc.) and, in some cases, assembling the transformer. The customer is not billed for any of these tasks.[23] However, the labor cost involved in connecting the transformer to the customer's service and the distribution system is recovered through the Installation Charge, so cost for that labor is not included as part of transformer installation costs. The material cost, including tax, and installation costs are listed for each transformer size in tables 7.17-7.21.

Table 7.14
Purchase Cost of Transformers, Network Protectors and Ancillary Equipment (including sales tax), 2004 data

		Transformers	Ancillary Equipmen and Materials	Network Protectors
25 kVA Transformer	Overhead	$1,064	$235	------
	Underground	$2,538	$289	------
50 kVA Transformer	Overhead	$1,441	$266	------
	Underground	$3,039	$289	------
75 kVA Transformer	Overhead	$1,989	$297	------
	Underground	$3,834	$566	------
100 kVA Transformer	Overhead	$2,707	$297	------
	Underground	$4,703	$566	------
167 kVA Transformer	Overhead	$4,196	$369	------
	Underground	$6,523	$1,001	------
750 kVA Comm'l Subway Transformer		$42,221	$1,354	------
1000 kVA Comm'l Subway Transformer		$50,437	$1,354	------
1500 kVA Comm'l Subway Transformer		$63,621	$1,354	------
2000 kVA Comm'l Subway Transformer		$75,320	$1,354	------
2500 kVA Comm'l Subway Transformer		$91,065	$1,354	------
5000 kVA Comm'l Subway Transformer		$172,825	$37,846	------
7500 kVA Comm'l Subway Transformer		$191,756	$37,846	------
15000 kVA Comm'l Subway Transforme		$479,477	$37,846	------
500 kVA Network Transformer		$40,390	$16,037	$40,453
750 kVA Network Transformer		$48,635	$16,037	$40,453
1000 kVA Network Transformer		$57,057	$16,037	$40,453
1500 kVA Network Transformer		$77,347	$16,037	$53,475
2000 kVA Network Transformer		$93,960	$16,037	$56,288

Based on estimates made in the EBASCO depreciation study, the expected life of transformers is 30 years. The 30-year life results in an annualization rate of .051019 at a 3% discount rate.

[23] Unless the customer requests some non-standard installation.

7.6.5 Operation and Maintenance Costs: Transformers

Annual O&M costs for transformers are tracked in FERC Account 595. Reported O&M in this account in 2005 was $456,128.

Not all transformers incur O&M expenses. After installation, transformers sized 167 kVA and smaller receive no maintenance. They are left alone unless they fail, at which time they are replaced, not repaired. Therefore, in this analysis, annual O&M costs are applied only to "large" transformers, i.e., those 500 kVA and larger. As can be seen in **Table 7.15**, this is done by dividing total annual transformer O&M costs by the total annual capital cost of large transformers. The resulting percentage is then applied to the capital cost of all large transformers. This is done in Tables 7.19 through 7.21. Large transformers make up 77.1 percent of total transformer capital costs in the Medium General Service class while all transformers serving Large General Service and High Demand customers are 500 kVA or larger.

Table 7.15
O&M as a Percent of Annual Transformer Capital Costs, $2005

Annual Transformer O&M Costs:		
2005 Transformer O&M costs (FERC Account 595) (including Social Security Taxes)		$456,128
Total Annual Capital Cost of Transformers Subject to O&M		
Total Medium General Service	$7,005,939	
Times % of MGS Subject to O&M	77.1%	
= Medium General Service Subject to O&M		$5,403,259
+ Large General Service		$2,984,897
+ High Demand		$530,937
= Total Annual Capital Cost Subject to O&M:		$8,919,093
O&M as Factor of Annual Capital Costs:		5.11%

7.6.6 Class Load Factors: Transformers

Information on load factors for transformers is needed for several reasons. For the Residential and Small General Service classes, load factors are used to estimate the noncoincident maximum demand (connected load). This is shown in **Table 7.16**. Because customers in the Medium, Large and High Demand classes have demand meters, their 2005 connected loads can be obtained directly from the billing records. Connected load for these classes does not have to be estimated from load factors. However, load factors for all the classes are necessary to forecast future connected load
Table 7.16 includes data for network and nonnetwork customers, separately, and for all customers combined for each class.

Table 7.16
Load Factors by Class, 2005

	MWH (a)	Connected Load, MW (b) (*)		Load Factor (c) (**)	
Residential, Total	**3,040,416**	**908**	(1)	**0.3821**	
Res., non-Network	2,970,135	891	(2)	0.3805	
Res., Network	70,281	17	(3)	0.4644	
Small G.S., Total	**1,162,324**	**345**	(1)	**0.3846**	
Small, non-Network	1,027,766	308	(2)	0.3805	
Small, Network	149,291	37	(3)	0.4644	
Medium G.S., Total	**2,297,475**	**621**		**0.4233**	(4)
Med., non-Network	1,705,925	510		0.4107	(4)
Med., Network	591,551	111		0.4644	(4)
Large G.S., Total	**1,362,279**	**357**		**0.4630**	(4)
Large, non-Network	734,699	200		0.4438	(4)
Large, Network	627,579	156		0.4877	(4)
High Demand	**1,042,232**	**258**		**0.4818**	(4)
Streetlights	**94,855**	**21**		**0.5237**	(5)

(1) Sum of Non-Network and Network
(2) Because customers in these classes do not have demand meters, connected load must be estimated by taking adjusted annual MWH (a) divided by the number of hours in the year (8760) divided by the estimated load factor (c).
(3) Residential and Small Network customers are assumed to use same transformers and have same load factor as Medium Network customers.
(4) For the 3 largest classes, the load factors are calculated by first dividing adjusted annual MWH (a) by 8760 to get average MW and then dividing that by the class noncoincident maximum demand (b) (i.e. connected load) from 2005 billing data.
(5) Streetlight load factor comes from engineering estimates.

7.6.7 Special Information by Class: Transformers

Residential

Through experience, transformer loadings for residential customers are estimated by the following formula:

$$\text{max demand} = 12\text{ kW} + .0003\ (\text{annual kWh}).$$

where "annual kWh" is the total for all the customers on that transformer. So, for each 1000 kWh of <u>added</u> annual load on a transformer, the maximum demand increases by 0.3 kW. We know that:

$$\text{Load Factor} = \frac{\text{Average kW}}{\text{Peak kW}}$$

So the Marginal Load Factor is:

$$\text{Marginal L. F.} = \frac{\text{Change in Average kW}}{\text{Change in Peak kW}} = \frac{1000\text{ kWh}/8760\text{ h}}{.3\text{ kW}} = 0.3805$$

Individual residential customers have a load factor smaller than this (in the neighborhood of .15), but since several residential customers are tied in to one transformer, some diversity results. In other words, not all of them will peak at once, so the overall peak is lower than adding all the separate peaks. This transformer loading formula has been confirmed with load research (see Seattle City Light, Demand Cost Allocation, September 1983, pp. 21-23).

Small General Service

In the absence of adequate load research, the transformer group load factor for the Small General Service class has been assumed to be 0.3805 -- the same load factor used for the Residential class. Small General Service customers might be expected to have slightly better load factors than individual residential customers because of a smaller saturation of electric space heat. On the other hand, Small General Service customers are, on average, larger than Residential customers, so fewer of them will fit on a single transformer. Fewer customers means less diversity and a lower load factor.

Several years ago, an average load factor of .2719 was computed for the approximately 4% of Small General Service customers with demand meters. However since there is no evidence that this group is representative of the majority of Small General Service customers, (i.e., those without demand meters,) this load factor is of little value. Furthermore, it is not the load factor of individual customers which is relevant, but the load factor of the transformer group. Until further research is completed, the same load factor used for the Residential class has been assumed to be representative of the load factor for the Small General Service class.

Medium, Large, and High Demand General Service

All customers in the Medium General Service, the Large General Service, and High Demand classes have demand meters. Accordingly, load factors can be computed directly from billing data. Unlike Residential and Small General Service customers, where the rule is a group of customers to one transformer, the rule for Medium, Large, and High Demand customers is at least one transformer to one customer. As a consequence, it is the load factor of each individual customer (or on each individual meter) which is relevant.

The load factors are derived directly from customer data for the Medium, Large, and High Demand classes. The load factor for each class is equal to average class demand for 2005 divided by the total class noncoincident maximum demand for 2005.

The first step in calculating average class demand is to calculate the average power MW for each class. Each customer’s energy consumption is divided by total number of hours billed. For example, consider a new customer who, having been first connected in March, is billed for only 285 days. Their total billed consumption in kWh is divided by 6840 (285 days times 24 hours per day) to derive an average power in kW (or kWh per hour). This produces an estimate of what the customer's power consumption would have been if he had been billed for a full year. Total average power use in MW for each class is obtained by adding up the adjusted annual energy use for all the customers in the class and dividing that sum by 1000.

Adjusted annual energy use in MWh for each class is the total average power multiplied by 8760 hours (hours in a year). Dividing this by the total class noncoincident maximum demand produces the load factor.

Streetlights

Streetlights are served at distribution voltage (26 kV for this marginal cost of service analysis) by short service drops from nearby transformers. Streetlights have neither energy nor demand meters. Their energy use for billing purposes is estimated according to the types and numbers of individual lamps and the hours they are on during the billing period.

For costing purposes, streetlights are assumed to have transformer capacity assigned according to the same design rules as Small General Service: i.e., the typical transformer serving a streetlight is a 50 kVA transformer with a loading rate of 100%. Therefore, the unit cost of transformer capacity is the same as that for Small General Service (Table 7.17).

Because streetlights are either on or off, load is constant when the lights are on and zero when they are off. Thus, peak load in kW is simply annual consumption in kWh divided by 4588 hours, the average number of hours the lights are on each year. Average annual kW equals annual kWh divided by 8760 hours, the total number of hours in the year. To calculate load factor, the annual kWh figures cancel; thus:

$$\text{Streetlight Load Factor} = \frac{\text{Average kW}}{\text{Peak kW}}$$

$$= \frac{\text{Annual kWh/8760}}{\text{Annual kWh/4588}}$$

$$= \frac{4588}{8760}$$

$$= 0.5237$$

Table 7.16 displays the load factors for all customer classes at the transformer level.

7.6.8 Computation of Costs by Class: Transformers

In **Tables 7.17 through 7.21**, all of the factors discussed in the preceding sections are combined to calculate annual transformer costs per kW for each class. As mentioned above, the "typical transformer" method is used for the Residential and Small General Service classes (Tables 7.17 and 7.18). For these classes, Annual Capital Cost (or "ACC" in the formulas) is obtained by summing the materials cost (augmented by the inventory reserve factor) and the installation cost for a 50 kVA transformer and multiplying that sum by the annualization factor. This is then levelized, (i.e., put on a per kW basis,) by dividing by the transformer size times the loading rate. The Levelized Capital Cost (LCC) is then multiplied by the loss factor to obtain the total transformer cost per kW per year.

For the Medium, Large, and High Demand General Service classes, (Tables 7.19, 7.20, and 7.21,) estimates of the number of transformers in each size category are used. These estimates are found in the "Frequency" column. The frequencies for the Medium and Large General Service classes are based on the frequencies from 2005. The computation of Annualized Capital Cost is similar to the process described for the smaller classes except that each material and installation cost is multiplied by the corresponding frequency and summed over all the transformer types and sizes. The result is the annualized capital cost for the entire class, not just the typical transformer. To obtain the Levelized Capital Cost, ACC must be divided by the noncoincident maximum demand for the whole class. The adjustment for losses is done in the same way as above.

Annual O&M cost (AOM) is calculated by multiplying the levelized capital cost adjusted for losses (AFL) by the O&M factor. For the Medium General Service class only, this product is multiplied by the percent of this class' capital cost that is actually subject to O&M. (100% of transformer capital costs are subject to O&M in the Large and High Demand classes.) Finally, AFL and AOM are added together to obtain the total annual transformer cost per kW for each class.

Tables 7.19 and 7.20 for Medium and Large General Service customers present estimates of transformer costs for each class as a whole though the costs for network and nonnetwork separately are used in the cost analysis for this rate case. Network cost estimates also were needed for Residential and Small General Service customers. Discussions with engineering staff suggested that these smaller classes could be thought to use the same types of transformers as Medium network customers with the understanding that many of the smaller customers would be served by these large transformers. The average cost for network transformer service for these smaller customers, therefore, is set equal to the cost for network transformers for Medium network customers.

Table 7.17
Residential Class Transformer Cost, $2005

Total Residential Transformer Cost =					**$3.081**	**/Kw/year**
	(A) Transformer Size (kVA)	**(B) Transformer Cost**	**(C) Ancillary quip. & Ma Cost**	**(D) nstallatior Cost**	**(E) requenc (#)**	**(F) Total Capacity (kVA)**
(1)	50	$2,457	$413	$1,563	n.a.	n.a.

	Assumptions:	
(a)	Inventory Reserve Factor	1.0175
(b)	Economic Life	30
(c)	Annualization Factor	0.051
(d)	Loading vs. Rating	150%
(e)	Losses	1.77%
(f)	O&M as % of Annual Capital Cost	0%
(g)	50 kVA OH Transformer Cost	$1,441
(h)	50 kVA UG Transformer Cost	$6,523
(i)	50 kVA OH Ancillary Equipment Cost	$266
(j)	50 kVA UG Ancillary Equipment Cost	$1,001
(k)	50 kVA OH Labor & Installation Cost	$663
(l)	50 kVA UG Labor & Installation Cost	$5,159
(m)	% Overhead transformers	80%

Annual Capital Cost Calculations			
Transformer Cost (TC) = (B)	=	(g) * (m) + (h) * [1-(m)]	
	=	$2,457.42	/year
Adjusted for Losses (TCAFL)	=	TC * {1 / [1 - (e)]}	
	=	$2,501.70	/kW/year
Annualized Capital Cost (ACC	=	{(a) *[(TCAFL)+ (C)] + (D)} * (c)	
	=	$231.043	/year
Levelized Capital Cost (LCC)	=	ACC / [(A) * (d)]	
	=	$3.081	/kW/year

Table 7.18
Small General Service Class and Streetlight Transformer Cost, $2005

Small Gen. Service & Stlt. Transformer Cost =						**$3.116 /kW/year**
	(A) Transformer Size (kVA)	**(B) Transformer Cost**	**(C) Ancillary Equip. & Mat'l Cost**	**(D) Installation Cost**	**(E) Frequency (#)**	**(F) Total Capacity (kVA)**
(1)	50	$1,601	$269	$1,113	n.a.	n.a.

	Assumptions:	
(a)	Inventory Reserve Factor	1.0175
(b)	Economic Life	30
(c)	Annualization Factor	0.051019
(d)	Loading vs. Rating	100%
(e)	Losses	2.31%
(f)	O&M as % of Annual Capital Cost	0%
(g)	50 kVA OH Transformer Cost	$1,441
(h)	50 kVA UG Transformer Cost	$3,039
(i)	50 kVA OH Ancillary Equipment Cost	$266
(j)	50 kVA UG Ancillary Equipment Cost	$289
(k)	50 kVA OH Labor & Installation Cost	$663
(l)	50 kVA UG Labor & Installation Cost	$5,159
(m)	% Overhead transformers	90%

Annual Capital Cost Calculations

Transforme	=	(g) * (m) + (h) * [1-(m)]
	=	$1,600.91 /year
Adjusted foı	=	TC * {1 / [1 - (e)]}
	=	$1,638.76 /year
Annualized	=	{(a) *[(TCAFL)+ (C)] + (D)} * (c)
	=	$155.793 /kW/year
Levelized C	=	ACC / [(A) * (d)]
	=	$3.116 /kW/year

Table 7.19
Medium General Service Class Transformer Cost, $2005

Medium General Service Transformer Cost, Combined =	**$11.754**	**/kW/year**
Medium General Service Transformer Cost, non-Network =	**$4.606**	**/kW/year**
Medium General Service Transformer Cost, Network =	**$35.064**	**/kW/year**

	(A) Transformer Size (kVA)	**(B) Transformer Cost**	**(C) Ancillary Equip. & Mat'l Cost**	**(D) Installation Cost**	**(E) 2005 Frequency (#)**	**(F) Total Capacity (kVA)**
Small (pole/sub)						
(1)	25	$1,359	$246	$1,563	1,659	41,475
(2)	50	$1,761	$271	$1,563	2,814	140,700
(3)	75	$2,358	$351	$1,890	1,122	84,150
(4)	100	$3,106	$351	$2,928	606	60,600
(5)	167	$4,661	$496	$2,928	810	135,270
% Ovr'hd xfmrs	80%				Total	462,195
Commercial Subway						
(6)	750	$42,221	$1,354	$8,439	135	101,250
(7)	1000	$50,437	$1,354	$8,439	41	41,000
(8)	1500	$63,621	$1,354	$8,439	15	22,500
(9)	2000	$75,320	$1,354	$8,439	0	0
(10)	2500	$91,065	$1,354	$8,439	0	0
Network					Total	164,750
(11)	500	$40,390	$56,490	$82,537	493	246,500
(12)	750	$48,635	$56,490	$82,537	30	22,500
(13)	1000	$57,057	$56,490	$82,537	0	0
(14)	1500	$77,347	$69,512	$82,537	0	0
(15)	2000	$93,960	$72,325	$82,537	0	0
					Total	269,000

	Assumptions:	**common**	**non-network**	**network**
(a)	Inventory Reserve Factor	1.0175		
(b)	Economic Life, years	30		
(c)	Annualization Factor	0.051019259		
(d)	Losses		0.98%	0.436%
(e)	Class Noncoincident Max Demand, kW	619,543	474,143	145,400
(f)	O&M as % of Annual Capital Cost	5.11%		
(g)	% of Capital Cost Subject to O&M	77.12%	25.65%	100.00%

Annual Capital Cost Calculations (all equations for "combined")			**combined**	**non-network**	**network**
Annualized Transformer Cost (ATC)	=	{[(a) * SUM(1...15)(B * E)]} * (c)			
	$/ year =		$2,367,490	$1,258,060	1,109,430
Adj. for Losses (AFL) = ATC / (1-d) [$/kW/yr]	=		$2,384,794	$1,270,511	$1,114,283
Annualized Material & Installation Cost (AMIC) = {(a)*SUM(1...15)(C*E)+SUM(1...15)(D*E)} =					
	$/ year =		$4,621,145	$885,099	$3,736,046
Ann. Cap. Cost (ACC) = AFL+AMIC [$/ year]	=		$7,005,939	$2,155,610	$4,850,329
Levelized Cap.Cost (LCC) = ACC/(e) [$/kW/yr]	=		$11.308	$4.546	$33.359
Annual O&M Calculations					
Ann.O&M (AOM) = LCC * (f) * (g) [$/kW/yr]	=		$0.446	$0.060	$1.706
Total Cost Calculations					
Total Cost = LCC + AOM [$/kW/yr]	=		$11.754	$4.606	$35.064

Table 7.20
Large General Service Class Transformer Cost, $2005

Large General Service Transformer Cost, Combined =	**$8.793**	**/kW/year**
Large General Service Transformer Cost, non-Network =	**$3.291**	**/kW/year**
Large General Service Transformer Cost, Network =	**$15.870**	**/kW/year**

	(A) Transformer Size (kVA)	**(B) Transformer Cost**	**(C) Ancillary Equip. & Mat'l Cost**	**(D) Installation Cost**	**(E) 1998 Frequency (#)**	**(F) Total Capacity (kVA)**
Commercial Subway:						
(1)	750	$42,221	$1,354	$8,439	4	3,000
(2)	1000	$50,437	$1,354	$8,439	3	3,000
(3)	1500	$63,621	$1,354	$8,439	43	64,500
(4)	2000	$75,320	$1,354	$8,439	35	70,000
(5)	2500	$91,065	$1,354	$8,439	12	30,000
(6)	5000	$172,825	$37,846	$113,082	8	40,000
(7)	7500	$191,756	$37,846	$114,604	3	22,500
Network					Total	233,000
(8)	500	$40,390	$56,490	$82,537	3	1,500
(9)	750	$48,635	$56,490	$82,537	39	29,250
(10)	1000	$57,057	$56,490	$82,537	33	33,000
(11)	1500	$77,347	$69,512	$82,537	102	153,000
(12)	2000	$93,960	$72,325	$82,537	21	42,000
					Total	258,750

	Assumptions:	**common**	**non-network**	**network**
(a)	Inventory Reserve Factor	1.0175		
(b)	Economic Life, years	30		
(c)	Annualization Factor	0.051019259		
(d)	Losses		0.89%	0.396%
(e)	Class Noncoincident Max Demand, kW	335,905	188,999	146,906
(f)	O&M as % of Annual Capital Cost	5.11%		

Annual Capital Cost Calculations (all equations for "coml	**combined**	**non-network**	**network**
Annualized Transformer Cost (ATC) = {[(a) * SUM(1...12)(B * E)]} * (c)			
$/ year =	$1,168,340	453,855	714,485
Adj. for Losses (AFL) = ATC / (1-d) [$/kW/yr] =	$1,175,253	$457,931	$717,323
Annualized Material & Installation Cost (AMIC) = {(a)*SUM(1...12)(C*E)+SUM(1...10)(D*E)} * (c)			
$/ year =	$1,634,518	$133,892	1,500,626
Ann. Cap. Cost (ACC) = AFL+AMIC [$/ year] =	$2,809,771	$591,823	$2,217,949
Levelized Cap.Cost (LCC) = ACC/(e) [$/kW/yr]=	$8.365	$3.131	$15.098
Annual O&M Calculations			
Ann.O&M (AOM) = LCC * (f) [$/kW/yr] =	$0.428	$0.160	$0.772
Total Cost Calculations			
Total Cost = LCC + AOM [$/kW/yr] =	$8.793	$3.291	$15.870

Table 7.21
High Demand General Service Class Transformer Cost, $2005

Total High Demand Transformer Cost =					**$2.165**	**/kW/year**
	(A) Transformer Size (kVA)	**(B) Transformer Cost**	**(C) Ancillary Equip. & Mat'l Cost**	**(D) Installation Cost**	**(E) 2005 Frequency (#)**	**(F) Total Capacity (kVA)**
Commercial Subway						
(1)	5000	$172,825	$39,346	$111,582	0	0
(2)	7500	$191,756	$39,346	$113,104	0	0
(3)	15000	$479,477	$39,346	$118,129	16	240,000
(4)	25000 (no longer used)	$0	$0	$0	0	0
(5)	30000 (no longer used)	$0	$0	$0	0	0

	Assumptions:	
(a)	Inventory Reserve Factor	1.0175
(b)	Economic Life, years	30
(c)	Annualization Factor	0.051019259
(d)	Losses	0.890%
(e)	Class Noncoincident Max Demand, kW	257,782
(f)	O&M as % of Annual Capital Cost	5.11%

Annual Capital Cost Calculations		
Annualized Transformer Cost (ATC)	=	{[(a) * SUM(1...5)(B * E)]} * (c)
	$/ year =	$398,250
Adj. For Losses (AFL) = ATC / (1-d) [$/kW/yr]	=	$401,827
Annualized Material & Installation Cost (AMIC)	= {(a)*SUM(1...5)(C*E)+SUM(1...5)(D*E)} * (c)	
	$/ year =	$129,111
Ann. Cap Cost (ACC) = AFL+AMIC [$/kW/yr]	=	$530,937
Levelized Cap. Cost (LCC) = ACC/(e) [$/kW/yr]	=	$2.060
Annual O&M Calculations		
Ann.O&M (AOM) = LCC * (f) [$/kW/yr]	=	$0.105
Total Cost Calculations		
Total Cost = LCC + AOM [$/kW/yr]	=	$2.165

7.6.9 Derivation of Cost Shares: Transformers

Table 7.22 presents the derivation of cost shares used to allocate customer transformer revenue requirements. As for wires and related equipment, revenue requirements for this functional category can be separated between nonnetwork and network customers in the derivation of functionalized revenue requirements. Thus, shares are needed, separately, for nonetwork and for network customer classes.

Load data come from Table 5.4 in Chapter 5. The Load Factor data come from Table 7.16. Peak MW equal Load / load factor / 8760. The $2005/MW come from Tables 7.17 through 7.21. The conversion factor to $2007 is derived from data in Table 4.1 in Chapter 4. The shares of cost for nonnetwork and network, separately, equal each class's share of the total cost over all classes in their separate groupings.

Table 7.22
Derivation of Cost Shares for Customer Transformers for 2007

	Total	Residential	Small	Medium	Large	High Demand	Lights
Data for 2007							
Total Nonnetwork (EXcludes Network Residential & Small)							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
MWH	8,137,774	3,096,874	1,047,363	1,846,776	898,097	1,153,749	94,915
Load Factor		0.3805	0.3805	0.4107	0.4438	0.4818	0.5237
Peak MW	2,260.99	929.10	314.22	513.29	231.03	273.34	20.69
2005$/kW		3.081	3.116	4.606	3.291	2.165	3.116
2007$/kW(*)		3.244	3.282	4.851	3.467	2.280	3.282
Total XfmrCost	8,027,554	3,014,415	1,031,151	2,489,951	800,889	623,254	67,894
Share of Cost	100.000%	37.551%	12.845%	31.018%	9.977%	7.764%	0.846%
Total Network (Includes Network Residential & Small)							
MWH	1,358,450	75,583	155,641	504,619	622,607		
Load Factor		0.4644	0.4644	0.4644	0.4877		
Peak MW	326.61	18.58	38.26	124.03	145.74		
2005$/kW		35.064	35.064	35.064	15.870		
2007$/kW(*)		36.930	36.930	36.930	16.714		
Total XfmrCost	9,115,233	686,073	1,412,766	4,580,469	2,435,925		
Share of Cost	100.000%	7.527%	15.499%	50.251%	26.724%		
(*) Adjustment to $2007 = 1.053189							
Data for 2008							
Total Nonnetwork (EXcludes Network Residential & Small)							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
MWH	8,290,732	3,162,046	1,069,385	1,884,141	912,641	1,167,604	94,915
Load Factor		0.3805	0.3805	0.4107	0.4438	0.4818	0.5237
Peak MW	2,304.56	948.66	320.83	523.68	234.77	276.62	20.69
2005$/kW		3.081	3.116	4.606	3.291	2.165	3.116
2008$/kW(*)		3.332	3.370	4.982	3.560	2.342	3.370
Total XfmrCost	8,404,459	3,160,954	1,081,259	2,608,918	835,833	647,768	69,727
Share of Cost	100.000%	37.610%	12.865%	31.042%	9.945%	7.707%	0.830%
Total Network (Includes Network Residential & Small)							
MWH	1,386,649	77,230	158,850	515,109	635,460		
Load Factor		0.4644	0.4644	0.4644	0.4877		
Peak MW	333.39	18.98	39.04	126.61	148.75		
2005$/kW		35.064	35.064	35.064	15.870		
2008$/kW(*)		37.927	37.927	37.927	17.165		
Total XfmrCost	9,556,047	719,951	1,480,826	4,801,931	2,553,340		
Share of Cost	100.000%	7.534%	15.496%	50.250%	26.720%		
(*) Adjustment to $2008 = 1.081625							
2007 + 2008							
Total Nonnetwork (EXcludes Network Residential & Small)							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total XfmrCost	16,432,013	6,175,369	2,112,410	5,098,870	1,636,722	1,271,021	137,621
Share of Cost	100.000%	**37.581%**	**12.855%**	**31.030%**	**9.961%**	**7.735%**	**0.838%**
Total Network (Includes Network Residential & Small)							
Total XfmrCost	18,671,280	1,406,024	2,893,592	9,382,400	4,989,265		
Share of Cost	100.000%	**7.530%**	**15.498%**	**50.250%**	**26.722%**		

Chapter 8

Customer-Related Costs

8.1 Introduction

Marginal customer-related costs are those costs associated with serving additional customers on the system, independent of the amount of energy consumed by these customers. Marginal customer-related costs are the sum of the annualized capital cost of meters and of annual customer-related operation and maintenance (O&M) costs. There are two broad categories of marginal customer-related costs. One, called **Customer Costs**, refers to the costs of meter reading, customer records and collections, and uncollectibles. The other, called **Meter and Service Drop Costs**, is comprised of the annualized capital cost of meters and service drops, and the annual operation and maintenance (O&M) costs of meters and service drops.

This second category of costs supports the distribution system. City Light must supply data to the Federal Energy Regulatory Commission (FERC) based on FERC guidelines. FERC assigns capital and O&M costs of meters and the O&M costs of service drops to distribution. Hence, even though these costs are independent of the amount of energy consumed, they are a logical part of distribution costs. This chapter explains how both categories of these customer-related costs are estimated but the meter and service drop costs are added to the costs of distribution-related costs and are used in developing cost shares to allocate distribution-related revenue requirements. Tables 8.26b and 8.27b here are used in Tables 7.10 and 7.12 in Sections 7.4.5 and 7.5, respectively, in Chapter 7.

Customer costs used to develop cost shares to allocate revenue requirements titled "Customer Costs" culminate below in Table 8.12b. The actual cost shares for these revenue requirements are derived at the end of the chapter in Table 8.28.

Pension and benefit expenses and the cost of Social Security taxes are included where appropriate. The analyses reported here utilize data from the year 2004 and are, therefore, in 2004 dollars. Since the test year for cost allocation is 2007, the results here are transformed in the final COSACAR model into dollars of those future years to account for expected inflation.

8.2 Overview of Customer-Related Data and Cost Allocation Procedure

8.2.1 Number of Customers

The customer counts used in this section are based on 2004 data, in order to match the 2004 Federal Energy Regulatory Commission (FERC) account data used for costs. These customer class numbers are taken from the 2004 Consolidated Customer Service System (CCSS) data files.

Each customer class is further distinguished by nonnetwork *vs*. network location within the City of Seattle in much of the following. Most tables presented in this chapter will have two versions, an "a" and a "b". The "a" version reflects data for integrated classes, i.e., where there is no distinction between network and nonnetwork customers. The "b" version reflects data for each class (except for High Demand) that is differentiated by network and nonnetwork. In a few cases, the sum of the components does not equal the total for the class because of certain reporting issues. The advantage of having both versions of the data is that this rate case uses both types of analyses. The majority of the analyses are on the basis of integrated classes with no distinction between network and nonnetwork customers. Some specialized analysis that did focus on the network and nonnetwork distinction, however, is also done. This chapter documents the customer-related costs for both types of COSACAR analyses.

All costs, except customer records and collections costs and the costs of uncollectibles, are determined initially on a "per meter" basis. For customer records and uncollectible costs, the initial cost base is the "account." For example, a commercial customer may have several meters at one business location, but the cost of billing, record keeping, and sending out notices is no greater than if the customer had only one meter. For purposes of cost allocation, therefore, the customer is charged only once for these costs, but ultimately the cost per account is adjusted to a cost per meter, so that the cost is on the same basis as the other customer costs.

The costs for customers who do not pay for the electricity that they use (uncollectibles) are also spread initially to customers in this cost allocation study on an account basis. All customers within the class share the costs of uncollectible revenues for a class. Customers in this cost allocation study, however, are only expected "to pay" their share of the uncollectibles costs once, even if they have several meters. After these costs per account are determined, similar to the customer records costs, they are converted to a cost per meter to be on the same basis as the other customer costs. These costs are allocated by account, rather than by meter, because bills are sent to customers and paid (or not paid) by account, not by meter.

Some customers, particularly multifamily dwellings and larger businesses, have more than one service and meter, but are billed for all meters under one account. The number of accounts, therefore, will be less than or equal to the number of meters.

In addition, some customers have multiple meters on one account, some of which are billed under one class's rate schedule and some under another class. In this case, the larger class (in terms of maximum demand definition) is assigned the account. Consider a metals processing firm that has one meter billed as Large General Service for its melting furnace, and another meter which measures electricity used to provide general plant and office light and heat that is billed as a Small General Service meter. In this case, there would be one Large General Service meter and one Small General Service meter, but only one account--a Large General Service Account.

Tables 8.1a and **8.1b** are a summary of meters and accounts by customer class as used in this chapter.

Table 8.1a

Meters and Accounts by Customer Class 2004

	Total System	Residential	Small General Service	Medium General Service	Large General Service	High Demand General Service
Meters	379,599	334,145	42,298	2,998	148	10
Accounts	364,981	331,413	30,724	2,694	141	9
Accounts/Meter	0.9615	0.9918	0.7264	0.8986	0.9527	0.9000

Table 8.1b

Meters and Accounts by Customer Class 2004

		Residential		Small General Service		Medium General Service		Large General Service		High Demand General
	Total System	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	Service
Meters	379,599	322,297	11,848	38,986	3,312	2,528	470	88	60	10
Accounts	364,981	319,772	11,641	28,311	2,413	2,285	409	81	60	9
Accts./Mtrs.	0.9615	0.9922	0.9825	0.7262	0.7286	0.9039	0.8702	0.9205	1.0000	0.9000

8.2.2 Description of Accounts

The three categories of information used in collecting, organizing, and ultimately calculating customer costs are shown in **Table 8.2**. The first set of information relates to organizational units (OU), which are specific groups of people within the Department. Employees are assigned to specific OUs and their labor cost is typically associated with that OU. Goods and services are purchased for OUs.

The second set of information relates to Projects, which are Departmental budget expenditure categories. These data were obtained from the Summit budget system reports ("Revenues and Expenditures by Project Detail"). All expenditures are assigned to a Project for budgetary purposes. Projects used in this report include the 2000 level, which refer to Customer Service and Conservation, and the 4000 level, which refer to Power Transmission and Distribution. Project information is available by total for each project and by each organizational unit.

Table 8.2

Organizational Components and Data Sources Used

Org. Unit	Org. Unit Name
323	Electric Service Engineers
341	North Customer Engineering
342	North Electrical Svc. & Construction
346	Power Systems Technology
351	South Electrical Svc. & Construction
352	South Customer Engineering
362	Network Engineering
365	Network Services
430	Customer Relations/ Account Services Director's Office
431	Account Executives
463	Credit
464	Customer Accounts
520	IT Director's Office
522	Infostructure Admin.
523	Customer & Manage-ment Systems
524	Utility Mgt. Systems
526	CCSS

Project #	Project Title
2114	Customer Records & Collections
2122	Customer Assistance
4280	Power Dist.: Maintain Overhead Lines
4282	Power Distribution: Maintain Underground Lines

FERC/ Summit #	FERC Name
45130	Misc.Svc.Rev.-Acct Change Fee (Resid.)
45131	Misc.Svc.Rev.-Acct Change Fee (Comm'l.)
45150	Misc.Svc.Rev.-Recon-nect & Field Charge
58611 58613	Meter Expenses
59710	Meter Maintenance
59350 59352 59353 59359	Overhead Line Maintenance
59440 59442 59460 59462	Underground Line Maintenance
90201	Meter Reading Exps.
90301 90311 90321 90331 90341 90351 90361	Customer Records and Collections Expenses
90401	Uncollectible Accounts
90801 90811	Customer Assistance

The third set of information relates to the Federal Energy Regulatory Commission (FERC) Chart of Accounts. FERC requires all energy utilities in the country to supply data utilizing a standard format. All expenditures and financial transactions are assigned to FERC accounts. The FERC information used in this chapter was taken from the 2004 annual subledger produced by General Accounting. That information includes: Revenue, which is located in the 400 level accounts[24]; Operation & Maintenance (O&M) expenses, which are located in the 500 level accounts; and Administration & General expenses (A&G), which are located in the 900 level accounts. Revenues and expenses are initially charged either directly to a FERC revenue or expense account, or to a work in progress FERC account through a work order. Generally, items initially charged to work in progress accounts are closed to (i.e. transferred to) FERC expense accounts on a monthly basis.

Labor costs charged to Projects include only direct costs for hours of labor. Labor costs charged to FERC accounts include direct costs, pensions and benefits, and costs of Social Security taxes. To put both project-specific and FERC costs on a comparable basis, it is necessary to multiply labor costs charged to Projects by a loading factor (in 2004 equal to 1.5865 for regular labor and 1.0765 for overtime labor) to include costs of pensions, benefits and Social Security.

[24] Some expenses are partially offset by revenues and it is only the net expenses that are appropriate to use in cost allocation.

There is often a close relationship between total expenses recorded in a Project and in a FERC account. The relationship may not be exact, though, because of slight differences in either definition of what is included, or when and how the economic transactions are recorded. In general, marginal costs developed here are based on FERC categories. The FERC accounts are typically most useful for organizing costs in a fashion that makes sense for the purposes of the analysis in this report. Additionally, results based on FERC accounts can potentially be compared between utilities on a reasonably meaningful basis. However, in some instances, data in FERC accounts do not cover exactly what is needed for purposes here. In these cases, relationships between Projects and FERC accounts are used to estimate what the "appropriate" FERC total is. In the discussion that follows, Project numbers that relate directly to a particular FERC account are given in parentheses. In some cases, portions of accounts within Projects are used to adjust FERC account totals. The following discussion explains when such adjustments are made. In a number of cases though, the costs relevant here are the total costs, including Social Security taxes, recorded in a FERC account. In these instances, no adjustments need be made using portions of Project data.

8.2.3 Customer Costs

Meter Reading. FERC Account 902 (Summit number 90201) contains meter reading costs. This account includes the labor, materials, and expenses incurred from reading meters and determining consumption.

Uncollectibles. FERC Account 904 (Summit number 90401) contains the costs of uncollectible accounts. These costs are the losses from uncollectible utility revenues.

Customer Records and Collections. A portion of FERC Account 903 (Project 2114, Summit numbers 90301-90361) contains customer record and collection expenses. These costs include billing and mailing costs; costs of customer contracts and orders; credit investigation; and records and collection expenses by City Light, collection agencies, the City Treasurer, banks or American Express. Cut-in and cut-out costs are excluded since these costs are collected directly through the Account Service Charge.

FERC Account 908 (Project 2122, Summit numbers 90801-90811) and a portion of Account 903 (Project 2114, Summit numbers 90301-90361) contain expenses related to assisting and advising customers. These include costs for service ranging from telephone assistance for any size customer to personal visits by technical personnel for consultation and advice to very large customers with unique services and operating needs.

8.2.4 Meter and Service Drop Costs

Meter Operation. All expenses in FERC Account 586 (Summit numbers 58611and 58613) are considered as marginal customer costs. Included in this account are costs of removal, reinstallation and resetting of meters, consultation on relocation of meters, inspecting and testing, office expenses, and engineering expense for the Meter Division.

Meter Maintenance. FERC Account 597 (Summit number 59710) contains meter maintenance costs. These costs include maintenance of meters and equipment and meter engineering.

Service Maintenance. Part of FERC accounts 593 (Summit number 59350-59359) and 594 (Summit numbers 59440-59462) contain the cost of labor, materials and expenses incurred in maintenance of the customer service "drop" for overhead and underground lines (some network and some nonnetwork), respectively. These customer-related costs are not kept separately in these FERC accounts so they must be estimated directly from activity reports of the number of maintenance calls received and follow-up visits made to maintain the service drops. The cost of replacement of service drops during routine maintenance performed by line crews has also been included in the service maintenance costs.

8.2.5 Pensions and Benefits

Pension and benefit expenses are allocated directly to each table as appropriate. Pensions and benefits are related to labor costs that are reported here in two different ways. One way involves direct labor costs. These labor costs are available from Budget reports from Summit. Pensions and benefits are allocated based on 58.68 percent of straight time labor dollars and 7.65 percent of overtime labor dollars. The 58.68 percent allocated to straight time labor dollars accounts for industrial insurance, health care, retirement benefits, death benefits, group life insurance, Social Security, medical aid and unemployment insurance.

The second way labor costs are gathered is as a component of FERC Account data. For FERC Account data, pension and benefit costs and Social Security costs are included.

8.2.6 Overview of Customer-Related O&M Cost Allocation Procedures

The procedures for allocating the costs to each class are described fully in the following sections. Briefly, the meter reading costs are allocated based on a study of the average number of meters read per assignment and the types of assignments presently serving a class of customers.

<u>Uncollectibles costs</u> are assigned to customer classes based on estimates of the amount of revenue “written-off,” i.e., associated with unpaid bills.

<u>Customer records costs</u> are allocated by a study of the year-end budget expenditures for customer records in five areas: 1) CIS and customer Accounts; 2) Credit; 3) Customer Engineering; 4) Account Executives; and 5) Customer Service Center. The costs for each of these five areas are then assigned to a customer class based on the types of customers who receive each type of service.

The meter operation and maintenance costs are allocated relative to the capital cost invested in each class of customers. Service maintenance costs are estimated based on a study of maintenance activities and budget expenditures. Service maintenance costs are assigned to classes in proportion to the total investment in service connection costs by class. The total investment in service connections is estimated based on installation charges in the

Departmental Policy and Procedures Manual cost schedule and on estimates by Customer Engineering employees.

All costs are calculated on a per meter basis except for customer records and uncollectible costs, which are calculated on an account basis. A customer receives only one bill regardless of how many meters there are for that account. Therefore, the account is the appropriate unit of analysis in these cases. For purposes of cost allocation, it is necessary to represent all costs on a per meter basis. For this reason, the customer records costs and uncollectible accounts costs are then adjusted in Table 8.5 to a per meter basis.

8.3 Customer Costs

The following components of marginal customer costs were analyzed for this study:

- Meter Reading Costs
- Costs of Uncollectibles
- Customer Records and Collections Costs

Uncollectibles and Customer Records and Collection Costs are calculated on the basis of cost per account, which is then translated to cost per meter. All other costs are determined on the basis of cost per meter.

8.3.1 Meter Reading

Meter reading costs for 2004, taken from FERC/Summit accounts, totaled $2,795,925, including Social Security taxes. These costs were apportioned to customer groups (in Tables 8.4a and 8.4b, discussed below) based on an estimate of the amount of meter reading resources used for each group. The resulting estimate of total meter reading costs per group was then converted to a cost per meter by dividing by the number of meters in each group. There are two steps in the calculation of meter reading costs.

Distribution of meter reading route types within customer groups

The average number of meters read for each type of route was based on discussions with meter readers. In order to develop an estimate of meter reading resources utilized for each group in this study, it was necessary to estimate the distribution of types of meter reading routes within the groups. There are two basic kinds of meter reading routes: driving and walking. Based on discussions with the meter reader manager, it was assumed that all nonnetwork customers in this study are served by driving routes. It was also assumed that customers in the downtown network are served by walking routes, whereas network customers in the University and First Hill areas are served primarily by driving routes.

Tables 8.3a and **8.3b** show the estimated number of meters on each type of route and the average reads per group for the meters analyzed in this study.

The average number of reads per group in Tables 8.3a and 8.3b is a hypothetical number reflecting the number of meters that would be on a "pure" route consisting only of customers of one group. In fact, routes usually include customers from more than one class. The hypothetical number of reads gives a relative index of the amount of meter reading effort that is used for each "sweep" of reading the meters for customers in a group. The lower the number, the greater the relative effort that is used to perform the meter reading activity.

Table 8.3a

Estimated Distribution of Customer Classes
By Type of Meter Route
(%)

	Number of Assignments	Avg. Reads/ Assignment	Residential	Small General Service	Medium General Service	Large General Service	High Demand General Service
Monthly Driving Assignments	97	160	0.10%	13.66%	66.75%	41.35%	40.00%
Monthly Walking Assignments	62	366	3.61%	15.06%	32.85%	58.65%	60.00%
Bimonthly Assignments	1200	325	96.29%	71.28%	0.40%	0.00%	0.00%
Average Reads per Class			326.32	308.64	228.33	280.81	283.60

Table 8.3b

Estimated Distribution of Customer Classes
By Type of Meter Route
(%)

	Number of Assign-ments	Avg. Reads per assign-ment	Residential		Small General Service		Medium General Service		Large General Service		High Demand General Service
			Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	
Monthly Driving Assignments	97	160	0.10%	0.00%	16.45%	0.00%	72.82%	29.76%	57.83%	14.00%	40.00%
Monthly Walking Assignments	62	366	0.00%	100.00%	6.17%	94.54%	26.71%	70.24%	42.17%	86.00%	60.00%
Bimonthly Assignments	1200	325	99.90%	0.00%	77.38%	5.46%	0.47%	0.00%	0.00%	0.00%	0.00%
Average Reads per Class			324.84	366.00	300.38	363.76	215.80	304.70	246.87	337.16	283.60

Meter reading cost per meter

Tables 8.4a and **8.4b** develop meter reading costs per meter using the total 2004 meter reading costs for the system and the information presented in Tables 8.3a and 8.3b. Meter reading costs (FERC/Summit account 902) were $2,795,925 in 2004. The first line of Tables 8.4, "Monthly Factor for Reads," equals the average number of months between meter readings for customers in each group. Residential, Small, and Medium General Service classes have some monthly and some bimonthly meter reading activity in the nonnetwork area. For these classes, the Monthly Factors are weighted averages that take into account the class's percentage of meters on monthly and bimonthly cycles and the average number of meter reads on walking and driving assignments. For example, the Monthly Factor for the Small General Service class in network areas in Table 8.3b equals:

$$\frac{(2 * 5.46\% * 325) + (94.54\% * 366)}{(5.46\% * 325) + (94.54\% * 366)} = 1.05$$

In the nonnetwork areas, 99.90% of all Residential meters are bimonthly read, so the Monthly Factor is 2.00. All of the meters in the Large and High Demand General Service classes are read monthly; therefore, the Monthly Factor is 1.00.

The second line of Tables 8.4 equals the product of the first line (Monthly Factor) and the Average Reads per Class from Tables 8.3. Class weights, on the third line, are normalized to the effort used to collect meter reading data for residential class customers (e.g., 650 nonnetwork reads and 366 network reads in Table 8.4b). The number of meters in the group times the group weight equals the weighted meters. The number of weighted meters in the group divided by the number of weighted meters in the system is used to allocate the total FERC meter reading costs to each customer group. Finally, the group cost share is converted to a cost per meter.

Table 8.4a Meter Reading Costs (2004$)					
	Residential	Small General Service	Medium General Service	Large General Service	High Demand General Service
Monthly Factors For Meter Reads	1.96	1.75	1.01	1.00	1.00
Total Reads per Class Times Monthly Factor	640	540	231	281	284
Class Weights	1.00	1.19	2.77	2.28	2.25
Meters	334,145	42,298	2,998	148	10
Weighted Meters	334,145	50,335	8,304	337	23
Share of Wt'd Meters	84.99%	12.80%	2.11%	0.09%	0.01%
Class Cost Share	$2,376,257	$357,878	$58,994	$2,516	$280
Meter Reading Cost per Meter	$7.11	$8.46	$19.68	$17.00	$28.00

Table 8.4b Meter Reading Costs (2004$)									
	Residential		Small General Service		Medium General Service		Large General Service		High Demand General Service
	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	
Monthly Factors For Meter Reads	2.00	1.00	1.84	1.05	1.01	1.00	1.00	1.00	1.00
Total Reads per Class Times Monthly Factor	650	366	553	382	218	305	247	337	284
Class Weights	1.00	1.78	1.18	1.70	2.98	2.13	2.63	1.93	2.29
Meters	322,297	11,848	38,986	3,312	2,528	470	88	60	10
Weighted Meters	322,297	21,089	46,003	5,630	7,533	1,001	231	116	23
Share of Wt'd Meters	79.79%	5.22%	11.39%	1.39%	1.86%	0.25%	0.06%	0.03%	0.01%
Class Cost Share	$2,230,869	$145,947	$318,456	$38,863	$52,004	$6,990	$1,678	$839	$280
Meter Reading Cost per Meter	$6.92	$12.32	$8.17	$11.73	$20.57	$14.87	$19.07	$13.98	$28.00

8.3.2 Customer Records and Collections

There are five component costs that are used in calculating customer records and collection costs. In all five areas, the account, rather than the meter, is the initial basis for customer cost calculations. The five areas are as follows:

- Consolidated Customer Service System (CCSS) Control and Account Services
- Credit and Collections
- Customer Engineering
- Account Executives
- Customer Accounts

Most data related to Customer Records and Collections expenses are recorded primarily in FERC/Summit 903 (Project 2114). However, Customer Engineering and Account Executives also use FERC/Summit 908 (Project 2122).

The amount of 2004 Customer Records and Collections expenses, as recorded in FERC 903 was $15,714,976 including Social Security taxes. As partial offsets to that expense, there were $515,719 collected for Account Service Charges (FERC/Summit 45130 plus FERC/Summit 45131) and one-half of the $114,122 recorded for Reconnect and Field Service Charges (FERC 45150). The amount of 2004 Customer Assistance, as recorded in FERC/Summit 90801 and 90811 (excluding conservation related expenditures in 90802), was $1,954,900 including Social Security taxes.

An Account Service Charge is collected when new accounts are established or a change of occupancy on an existing premises requires a change in the account. This revenue reduces the costs the Department must collect through electricity rates. Accordingly, for cost of service analysis purposes, the amount collected for Account Service Charges is deducted from the portion of FERC 903 that is assigned to CCSS and Customer Accounts, so that the cost per account reflects the actual cost to the Department of providing these services.

In a similar manner, a portion of the Reconnect and Field Service Charges collected are deducted from the portion of FERC 903 assigned to Credit. These charges are assessed when electric service is disconnected for nonpayment of bills. No charge is assessed for reconnecting the service unless it is reconnected after working hours Monday through Friday or on holidays or weekends. Service disconnection is generally done by customer representatives. The reconnection is done by meter electricians during normal work hours or line crews after normal work hours and on weekends. It was assumed that 50% of the collection would be for the disconnect and 50% for the reconnect. Therefore, 50% of the Reconnect and Field Service Charge (FERC 45150) collected ($114,122) is deducted from the portion of FERC 903 assigned to Credit prior to the calculation of the cost per account for that function.

The Customer Records and Collection expenses are assigned to the five major areas listed above using the proportions of each functional area's expenditures (as identified by Organizational Units) to the total of 2004 Project 2114 and Project 2122 expenditures reported in Summit. The amounts assigned to CCSS and Customer Accounts, and to Credit are reduced by the Account Service Charge collections and the Reconnect and Field Service Charge collections, respectively, as noted above. Each major area's expenditure is then allocated to the customer classes, and costs per account by customer class are calculated. **Tables 8.5a** and **8.5b** summarize the five areas that make up Customer Records and Collections costs. Derivations of the costs are detailed in Tables 8.6 through 8.10.

Table 8.5a

Customer Records & Collection Costs Summary (2004$)

	Residential	Small General Service	Medium General Service	Large General Service	High Demand General Service
CCSS & Customer Accts.[1]	$20.86	$25.89	$40.07	$38.84	$40.23
Credit[2]	$8.50	$7.65	$19.33	$1,278.24	$0.00
Customer Engineering[3]	$13.25	$12.95	$10.52	N/A	N/A
Account Executives[4]	N/A	$1.63	$55.68	$2,482.22	$49,998.95
Customer Service Center[5]	$20.26	$19.80	$16.08	N/A	N/A
Total Records & Collections Cost Per Account	$62.87	$67.92	$141.68	$3,799.30	$50,039.17
Account Meter Ratio[6]	0.9918	0.7264	0.8986	0.9527	0.9000
Adjusted to Cost Per Meter	$62.35	$49.33	$127.31	$3,619.60	$45,035.26
Total Class Cost	$20,833,941	$2,086,560	$381,675	$535,701	$450,353
Share (%)	85.8%	8.6%	1.6%	2.2%	1.9%

[1]Table 8.6a [4]Table 8.9a
[2]Table 8.7a [5]Table 8.10a
[3]Table 8.8a [6]Table 8.1a

Table 8.5b Customer Records & Collection Costs Summary (2004$)									
	Residential		Small General Service		Medium General Service		Large General Service		High Demand General Service
	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	
CCSS & Customer Accts.[1]	$20.16	$40.28	$24.70	$39.18	$40.18	$40.28	$40.28	$40.28	$40.28
Credit[2]	$8.50	$8.50	$7.65	$7.65	$20.81	$11.10	$2,225.08	$0.00	$0.00
Customer Engineering[3]	$13.24	$13.24	$12.94	$12.94	$11.97	$12.98	N/A	N/A	N/A
Account Executives[4]	N/A	N/A	$1.63	$1.63	$55.68	$55.68	$3,191.42	$3,191.42	$38,888.07
Customer Service Cntr.[5]	$20.24	$20.24	$19.78	$19.78	$18.30	$19.84	N/A	N/A	N/A
Total Records & Collections Cost Per Account	$62.14	$82.26	$66.69	$81.18	$146.94	$139.88	$5,456.78	$3,231.70	$38,928.35
Account Meter Ratio[6]	0.9922	0.9825	0.7262	0.7286	0.9039	0.8702	0.9205	1.0000	0.9000
Adjusted to Cost Per Meter	$61.65	$80.82	$48.43	$59.14	$132.82	$121.72	$5,022.72	$3,231.70	$35,035.51
Total Class Cost	$19,869,523	$957,537	$1,888,160	$195,880	$335,767	$57,211	$441,999	$193,902	$350,355
Share (%)	81.8%	3.9%	7.8%	0.8%	1.4%	0.2%	1.8%	0.8%	1.4%

[1]Table 8.6a [4]Table 8.9a
[2]Table 8.7a [5]Table 8.10a
[3]Table 8.8a [6]Table 8.1a

CCSS Systems Control and Account Services

These services include the costs of the automated records system, the billing system and other account services. **Tables 8.6a** and **8.6b** show the portion of Customer Records and Collection Costs contributed by CCSS Systems Control and Account Services.

Group weights in Tables 8.6 are based on the portion of monthly and bimonthly billed customers in each customer class, where Residential equals 1 to indicate bimonthly billing. Since the Large and High Demand General Service accounts are monthly billed, their weight is 2. Weighted accounts are calculated by multiplying the group weight times the number of accounts in the group. The total 2004 system cost for this category, from FERC accounts, was $7,823,219. This amount equals the proportion of total Project 2114 assigned to the Customer Accounts Organizational Unit 464 in 2004. That proportion, 46.86%, was multiplied by the total 2004 FERC 903 account ($15,714,976), including Social Security taxes, producing the amount $7,364,561. From that amount, Account Services Charges (FERC/Summit accounts 45130 and 45131) collected of $515,719 were subtracted. Group cost shares are calculated as the group's proportion of the 388,932 total system weighted accounts.

Table 8.6a

Customer Records & Collections Costs
CCSS Systems Control & Account Services
(2004$)

Total (System)	Residential	Small General Service	Medium General Service	Large General Service	High Demand General Service
364,981	331,413	30,724	2,694	141	9
	1.04	1.29	2.00	2.00	2.00
388,932	343,708	39,547	5,377	282	18
100%	88.37%	10.17%	1.38%	0.07%	0.00%
$7,823,219	$6,913,553	$795,472	$107,960	$5,476	$362
$21.43	$20.86	$25.89	$40.07	$38.84	$40.23

Table 8.6b

Customer Records & Collections Costs
CCSS Systems Control & Account Services
(2004$)

	Total (System)	Residential		Small General Service		Medium General Service		Large General Service		High Demand General Service
		Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	
Number of Accounts	364,981	319,772	11,641	28,311	2,413	2,285	409	81	60	9
Class Weights		1.00	2.00	1.23	1.95	2.00	2.00	2.00	2.00	2
Weighted Accounts	388,459	320,090	23,282	34,716	4,694	4,559	818	162	120	18
Class Share	100.00%	82.40%	5.99%	8.94%	1.21%	1.17%	0.21%	0.04%	0.03%	0.00%
Class Cost Shares	$7,823,219	$6,446,323	$468,878	$699,144	$94,538	$91,821	$16,474	$3,263	$2,417	$363
Cost Per Account	$21.43	$20.16	$40.28	$24.70	$39.18	$40.18	$40.28	$40.28	$40.28	$40.28

Credit and Collections

Tables 8.7a and **8.7b** show the Credit and Collections portion of Customer Records and Collections Costs. Group weights are derived from the cost of uncollectibles per account (Tables 8.11a and 8.11b). The Residential class weight is set equal to 1.00 and other weights equal the ratio of each group's uncollectibles cost to the corresponding cost for the Residential class. The total system class cost share in Tables 8.7 is based on the proportion of the total Project 2114 that is assigned to Organizational Unit 463 (Credit). That proportion, 21.26%, is multiplied by the total in FERC/Summit Account 903, including Social Security taxes, producing the amount $3,340,795. Then 50% of the $114,122 of Reconnect and field Service Charges (FERC/Summit 45150) collected in 2004 were subtracted. The resulting net 2004 cost for Credit is $3,283,734. Group cost shares are calculated from the group's share of the 386,398 weighted accounts in the system. Costs per account are the result of class cost shares divided by the number of accounts. Credit costs per account by customer class are shown in Tables 8.7a and b.

Table 8.7a

Customer Records & Collections Costs
Credit & Collections
(2004$)

	Total (System)	Residential	Small General Service	Medium General Service	Large General Service	High Demand General Service
Uncollectible Cost Per Account		$26.55	$23.89	$60.38	$3,993.13	$0.00
Weights (Res. = 1.0)		1.00	0.90	2.27	150.41	0.00
Number of Accounts	364,981	331,413	30,724	2,694	141	9
Weighted Accounts	386,398	331,413	27,650	6,127	21,208	0
Class Share	100.00%	85.77%	7.16%	1.59%	5.489%	0.000%
Class Cost Share	$3,283,734	$2,816,453	$234,982	$52,067	$180,232	$0
Credit & Collections Cost Per Account	$9.00	$8.50	$7.65	$19.33	$1,278.24	$0.00

*Residential=1.0 ($26.55)

Table 8.7b

Customer Records & Collections Costs
Credit & Collections
(2004$)

	Total (System)	Residential		Small General Service		Medium General Service		Large General Service		High Demand General Service
		Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	
Uncollectible Cost Per Account		$26.55	$26.55	$23.89	$23.89	$64.98	$34.65	$6,951.01	$0.00	$0.00
Weights* (Res. = 1.0)		1.00	1.00	0.90	0.90	2.45	1.31	261.83	0.00	0.00
Number of Accounts	364,981	319,772	11,641	28,311	2,413	2,285	409	81	60	9
Weighted Accounts	386,398	319,772	11,641	25,479	2,172	5,593	534	21,208	0	0
Class Share	100.00%	82.76%	3.01%	6.59%	0.56%	1.45%	0.14%	5.489%	0.000%	0.000%
Class Cost Share	$3,283,734	$2,717,522	$98,929	$216,527	$18,455	$47,531	$4,538	$180,232	$0	$0
Credit & Collections Cost Per Account	$9.00	$8.50	$8.50	$7.65	$7.65	$20.81	$11.10	$2,225.08	$0.00	$0.00

Customer Engineering

Customer Engineering services are provided to Residential, Small General Service, and most Medium General Service customers. To determine the Customer Engineering portion of the Customer Records and Collections costs, group cost shares are calculated as each group's proportion of all accounts receiving the service multiplied by the total system cost.

Customer Engineering costs are found in both Project 2114 and Project 2122. These relate directly to FERC 903 and FERC 908. The proportion of FERC 903 attributable to Customer Engineering is calculated from the proportion of total Project 2114 assigned to the Organizational Units 341 and 352 in 2004. That proportion, 19.19%, is multiplied by the total 2004 FERC 903 account, including Social Security taxes. The same process is conducted with Project 2122, multiplying the percentage result of 92.26% to get the portion of FERC/Summit 90801 and 90811 attributable to Customer Engineering. The resulting 2004 cost for Customer Engineering is the sum, which is $4,818,817.

Once again, class cost shares are calculated using the classes' proportions of accounts to the total accounts multiplied by the total system 2004 Customer Engineering cost. **Tables 8.8a** and **8.8b** show the accounts to which Customer Engineering services are provided and the cost per account.

Table 8.8a
Customer Records & Collections Costs
Customer Engineering
(2004$)

	Total (System)	Residential	Small General Service	Medium General Service	Large General Service	High Demand General Service
Total Accounts in Classes Served	364,831	331,413	30,724	2,694	N/A	N/A
Accounts Served by Customer Engineering	363,581	331,413	30,030	2,138	N/A	N/A
Class Share	100.00%	91.15%	8.26%	0.59%	N/A	N/A
Class Cost Share	$4,818,817	$4,392,470	$398,011	$28,337	N/A	N/A
Customer Engineering Cost Per Account	$13.21	$13.25	$12.95	$10.52	N/A	N/A

Table 8.8b Customer Records & Collections Costs Customer Engineering (2004$)										
	Total (System)	Residential		Small General Service		Medium General Service		Large General Service		High Demand General Network
		Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork		
Total Accounts in Classes Served	364,831	319,772	11,641	28,311	2,413	2,285	409	N/A	N/A	N/A
Accounts Served by Customer Engineering	363,910	319,772	11,641	27,672	2,358	2,066	401	N/A	N/A	N/A
Class Share	100.0%	87.87%	3.20%	7.60%	0.65%	0.57%	0.11%	N/A	N/A	N/A
Class Cost Share	$4,818,817	$4,234,351	$154,148	$366,420	$31,231	$27,358	$5,310	N/A	N/A	N/A
Customer Engineering Cost Per Account	$13.21	$13.24	$13.24	$12.94	$12.94	$11.97	$12.98	N/A	N/A	N/A

Account Executives

Account Executive (Unit 431) services are currently provided to all Large and High Demand General Service customers. Staff in this unit also serve industrial customers in the Medium General Service class, and Small and Medium General Service meters that are part of the service for Large and High Demand customers.

Account Executive costs are found in both Project 2114 and Project 2122, and in FERC 903 and 908. The share of FERC 903 (5.54%) assigned to Unit 431 is $869,996. The proportion of FERC 908 (6.65%) assigned to Unit 431 is $129,983. The resulting 2004 cost for Account Executives services is therefore, $999,979.

Account Executives costs are spread across the customer classes according to percentages provided by the 2004 Account Executives manager. These percentages are not directly based on the number of accounts that were served by the unit in 2004. The costs per account calculations by customer class are based on the class cost shares of costs divided by the total accounts in the class. Account Executives costs per account by customer class are shown in **Tables 8.9a** and **8.9b**.

Table 8.9a Customer Records & Collections Costs Account Executives & Electric Service Engineering (2004$)						
	Total (System)	Residential	Small General Service	Medium General Service	Large General Service	Demand General Service
Total Accounts in Classes Served	33,568	N/A	30,724	2,694	141	9
Accounts Served by Account Executives	1,400	N/A	694	556	141	9
Class Share	100.00%	N/A	5.00%	15.00%	35.00%	45.00%
Class Cost Share	$999,979	N/A	$49,999	$149,997	$349,993	$449,991
Account Executives Cost Per Account	$29.79	N/A	$1.63	$55.68	$2,482.22	$49,998.95

Table 8.9b Customer Records & Collections Costs Account Executives & Electric Service Engineering (2004$)										
	Total (System)	Residential		Small General Service		Medium General Service		Large General Service		High Demand General
		Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	
Total Accounts in Classes Served	33,568	N/A	N/A	28,311	2,413	2,285	409	81	60	9
Accounts Served by Account Executives	1,400	N/A	N/A	639	55	472	84	81	60	9
Class Share	100.00%	N/A	N/A	4.61%	0.39%	12.72%	2.28%	25.85%	19.15%	35.00%
Class Cost Share	$999,979	N/A	N/A	$46,072	$3,927	$127,224	$22,772	$258,505	$191,485	$349,993
Account Executives Cost Per Account	$29.79	N/A	N/A	$1.63	$1.63	$55.68	$55.68	$3,191	$3,191	$38,888

Customer Accounts

Customer assistance by Customer Accounts, Organizational Unit 464, is provided to Residential, Small General Service, and Medium General Service commercial customers. These costs are calculated by the same process as Account Executives costs. They are found in the portion of Project 2114 (FERC 903) assigned to Unit 464. Based on 2004 Summit records, the proportion of FERC 903 (46.86%) assigned to Unit 464 is $7,364,561. Note: in the 1999 COSACAR, these costs were assigned to the Customer Service Center (Unit 465). In 2003, Unit 465 was closed in City Light's records; the employees of Unit 465 are now Seattle Public Utilities (SPU) staff. Customer Accounts costs are spread across the customer classes in proportion to the number of accounts in each of these classes. Costs per account by customer class are based on the class share of costs divided by the total accounts in the class. Customer Accounts costs per account by customer class are shown in Tables **8.10a** and **8.10b.**

Table 8.10a

Customer Records & Collection Costs
Customer Service Center Costs
(2004$)

	Total System	Residential	Small General Service	Medium General Service	Large General Service	High Demand General Service
Total Accounts in Classes Served	364,831	331,413	30,724	2,694	N/A	N/A
Accounts Served by Customer Serv. Cntr.	363,581	331,413	30,030	2,138	N/A	N/A
Class Share	100.00%	91.15%	8.26%	0.59%	N/A	N/A
Class Cost Share	$7,364,561	$6,712,978	$608,277	$43,307	N/A	N/A
Customer Serv. Cntr. Cost Per Account	$20.19	$20.26	$19.80	$16.08	N/A	N/A

Table 8.10b

Customer Records & Collection Costs
Customer Service Center Costs
(2004$)

	Total System	Residential		Small General Service		Medium General Service*		Large General Service		High Demand General Service
		Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	Non-network	Network	
Total Accounts in Classes Served	364,831	319,772	11,641	28,311	2,413	2,285	409	N/A	N/A	N/A
Accounts Served by Customer Serv. Cntr.	363,910	319,772	11,641	27,672	2,358	2,066	401	N/A	N/A	N/A
Class Share	100.00%	87.87%	3.20%	7.60%	0.65%	0.57%	0.11%	N/A	N/A	N/A
Class Cost Share	$7,364,561	$6,471,327	$235,583	$559,997	$47,730	$41,810	$8,115	N/A	N/A	N/A
Customer Serv. Cntr. Cost Per Account	$20.19	$20.24	$20.24	$19.78	$19.78	$18.30	$19.84	N/A	N/A	N/A

8.3.3 Cost of Uncollectibles

The uncollectible costs per account by customer class are shown in **Tables 8.11**a and **8.11b.** Marginal uncollectible expenses are computed based on the relative contribution of each class to the annual uncollectible revenue for City Light. Tables 8.11 provide information on how the Uncollectibles costs are allocated to each class. This information is estimated from a 2004 year-end Consolidated Customer Service System (CCSS) report on accounts sent to collection agencies ("Bad Debt Write-offs and Recoveries Summary"). This report has information by customer class, but does not reflect amounts recovered. To estimate the 2004 Uncollectibles costs by class, FERC Account 904, which totaled $10,258,165, was allocated to the classes in the proportions estimated from customer class information in the CCSS report, and then divided by the number of accounts. The account is the appropriate basis for initially determining costs, because the costs for all meters for a customer are considered as one uncollectible account when writing off a bad debt. The last two lines of the table, though, show the conversion of cost per account to a cost per meter basis in order to be consistent with results in other tables.

Table 8.11a

Uncollectible Costs (2004$)

	Total (System)	Residential	Small General Service	Medium General Service	Large General Service	High Demand General Service
Class % of Total Write-off	100.00%	85.77%	7.16%	1.59%	5.489%	0.000%
Total Accounts	364,981	331,413	30,724	2,694	141	9
Class Cost Share	$10,258,165	$8,798,410	$734,069	$162,654	$563,032	$0
Uncollectible Cost Per Account	$28.11	$26.55	$23.89	$60.38	$3,993.13	$0.00
Account: Meter Ratio		0.9918	0.7264	0.8986	0.9527	0.9000
Adjusted to Cost Per Meter		$26.33	$17.35	$54.25	$3,804.27	$0.00

Table 8.11b Uncollectible Costs (2004$'s)										
	Total (System)	Residential		Small General Service		Medium General Service		Large General Service		High Demand General Service
		Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	
Class % of Total Write-off	100.00%	82.76%	3.01%	6.59%	0.56%	1.45%	0.14%	5.49%	0.00%	0.000%
Total Accounts	364,981	319,772	11,641	28,311	2,413	2,285	409	81	60	9
Class Cost Share	$10,258,165	$8,489,363	$309,047	$676,417	$57,652	$148,482	$14,172	$563,032	$0	$0
Uncollectible Cost Per Account	$28.11	$26.55	$26.55	$23.89	$23.89	$64.98	$34.65	$6,951.01	$0.00	$0.00
Account/Meter Ratio		0.9922	0.9825	0.7262	0.7286	0.9039	0.8702	0.9205	1.0000	0.9000
Adjusted to Cost Per Meter		$26.34	$26.08	$17.35	$17.41	$58.73	$30.15	$6,398.09	$0.00	$0.00

8.3.4 Summary of Customer Costs by Class

Tables 8.12a and **8.12b** summarize customer costs calculated thus far in this chapter. Costs are in 2004 dollars and are expressed in terms of cost per meter. Results from Table 8.12b are used in constructing cost shares used to allocate Customer Cost revenue requirements. These cost shares are developed in Section 8.5, the last section of this chapter.

Table 8.12a Marginal Customer Costs by Customer Class (2004$)					
	Residential	Small General Service	Medium General Service	Large General Service	High Demand General Service
Meter Reading	$7.11	$8.46	$19.68	$17.00	$28.00
Customer Records & Collections	$62.35	$49.33	$127.31	$3,619.60	$45,035.26
Uncollectibles	$26.33	$17.35	$54.25	$3,804.27	$0.00
Total Customer Costs per Meter	$95.79	$75.15	$201.24	$7,440.87	$45,063.26

Table 8.12b Marginal Customer Costs by Customer Class (2004$)									
	Residential		Small General Service		Medium General Service		Large General Service		High Demand General Service
	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	
Meter Reading	$6.92	$12.32	$8.17	$11.73	$20.57	$14.87	$19.07	$13.98	$28.00
Customer Records & Collections	$61.65	$80.82	$48.43	$59.14	$132.82	$121.72	$5,023	$3,232	$35,036
Uncollectibles	$26.34	$26.08	$17.35	$17.41	$58.73	$30.15	$6,398.09	$0.00	$0.00
Total Customer Costs per Meter	$94.91	$119.22	$73.95	$88.28	$212.13	$166.75	$11,440	$3,246	$35,064

8.4 Meter and Service Drop Costs

The following components of marginal customer costs were analyzed for this study:

- Meter Capital Costs
- Meter Operation Costs
- Meter Maintenance Costs
- Service Maintenance Costs

Costs are determined on the basis of cost per meter. The number of meters and accounts, and their corresponding ratio, for the customer groups analyzed are shown previously in Table 8.1.

8.4.1 Meter Capital Costs

Meter Costs of Typical Service

The annual capital cost of meters consists of the cost of meters, metering equipment and certain shop costs for preparing meters for installation. Not all customers have the same kind of meters and metering equipment. There are twelve service types described in **Table 8.13** ranging from single-phase, 125 amperes to three-phase, 2400 amperes designed for 13.8 kV and 20,000 kVA. These twelve are representative of the many different types of meters actually used.

Additional metering equipment may include time-of-use solid-state registers.

Table 8.13 indicates the cost items included in determining the total meter capital costs by service type. For services greater than 225 amperes, current transformers must be used that are rated at the amperage of the service connection. Services of over 480 volts additionally must include potential transformers. Services that include reactive metering no long require

Table 8.13

Meter Costs for Typical Electric Service by Service Type (2004$)

Materials	Service #1* Single Phase 125 amp	Service #2 * Single Phase 225 amp	Service #3 Three Phase 225 amp	Service #4 Three Phase 400 amp w/CT w/demand mtr.	Service #5 3 phase-400 amp 277/480V 300 max kVA w/demand meter w/o reactive mtr	Service #6 3 phase-800 amp 277/480V 665 max kVA w/demand meter w/o reactive mtr
Kwh Meter	$22.11	$57.17	$147.02	$287.50	$287.50	$287.50
Current Transformer				$48.79	$48.79	$48.79
Potential Transformer						
Security	$1.00	$1.00	$1.00	$24.63	$24.63	$24.63
Total	$23.11	$58.17	$148.02	$360.92	$360.92	$360.92

Materials	Service #7 3 phase-400 amp 277/480V 300 max kVA w/demand meter w/reactive meter	Service #8 3 phase -800 amp 277/480V 665 max kVA w/demand meter w/reactive meter	Service #9 3 phase-2400 amp 277/480V 1995 max kVA w/TOU register w/reactive meter	Service #10 3 phase-600 amp 7.97/13.8 kV 7500 max kVA w/TOU register w/reactive meter	Service #11 3 phase-3000 amp 4kV 10,000 kVA w/TOU Register w/reactive meter	Service #12 3 phase 2400 amp 13.8 kV 20,000 kVA w/TOU register w/reactive meter
Kwh Meter	$287.50	$287.50	$287.50	$287.50	$287.50	$287.50
Current Transformer	$128.70	$49.27	$49.27	$328.73	$502.42	$1,663.60
Potential Transformer				$495.88	$785.40	$1,323.00
Security	$86.95	$102.53	$102.53	$69.05	$69.05	$69.05
Total	$503.15	$439.30	$439.30	$1,181.16	$1,644.37	$3,343.15

* Single phase meters in the Nonnetwork cost $23.11, shown in the table; single phase meters in the Network cost $99.83. Cost of meters includes 8.9% sales tax

a separate meter for this purpose. Advances in technology brought about by the industry shift from electromechanical meters to electronic meters have enabled a single piece of equipment to serve as a kWh meter, a kW meter, and a reactive meter. Phase shifters are also no longer required, because recently manufactured meters are able to internally perform this function as well.

If a customer has a time-of-use solid state meter, there are additional capital costs in purchasing the meter. The larger the demand, the more expensive the meters that monitor consumption. The metering equipment for a High Demand customer can cost more than 150 times more than the metering equipment for a typical residential customer.

Distribution of Service Types by Customer Class

The marginal capital costs for purchasing meters and metering equipment have been assigned to each customer class based on the estimated distribution of these twelve types of service within each class. Table 8.13 presents meter cost information (from Power Systems Technology staff) for the year 2004. **Tables 8.14a** and **8.14b** present estimates (from South Electrical Services Director) of the percentage of customers within each class that are assumed would use each type of meter if the customers were to have meters installed using current guidelines.

For Residential and Small General Service customers, the number of meters with each type of configuration was based on Consolidated Customer Information System (CCSS) tallies of service type by customer type. All Residential meters (except a very few very large residences) have either configuration #1 or #2.

For Medium and Large General Service customers, the number of meters with each type of configuration was estimated using historical maximum demand (kW) and the presence of a reactive meter. This information was taken from 2004 customer billing records. It is generally the policy of the department to install a service configuration at any given site that is somewhat "oversized" in order to insure adequate service levels. After discussions with Meter Reading staff, the distribution of each service configuration was based on thresholds set 10% below those defined by the configuration. For example, configuration #8 meters were, for purposes of this study, defined as those with maximum kW of 665 (the maximum kVa which defines the service); configuration #9 meters were defined as those with greater than 665 kW and a maximum kW of 1995, etc. The current policy of the department is that all Large General Service accounts are installed with reactive meters.

The estimated number of customers with each type of meter configuration is shown in Tables 8.14a and 8.14b.

Table 8.14a Distribution of Service Type By customer Class			
Customer Class	Service Type	# in Class	% of Class*
Residential	1	165,578	49.6%
	2	165,566	49.6%
	3	3,000	0.9%
Small General Service	2	25,675	60.7%
	3	16,623	39.3%
Medium General Service	4	1,406	46.9%
	5	339	11.3%
	6	237	7.9%
	7	627	20.9%
	8	390	13.0%
Large General Service	8	5	3.4%
	9	71	47.7%
	10	72	48.3%
	12	1	0.7%
High Demand	12	10	100.0%

Table 8.14b DISTRIBUTION OF SERVICE TYPE By customer Class							
	Service	**Nonnetwork**		**Network**		**Total**	
Customer Class	Type	# in Class	% of Class*	# in Class	% of Class*	# in Class	% of Class*
Residential *	1	159,702	49.6%	5,877	49.6%	165,573	49.6%
	2	159,702	49.6%	5,865	49.5%	165,573	49.6%
	3	2,900	0.90%	100	0.84%	3,000	0.90%
Small General Service *	2	25,583	65.6%	546	16.5%	25,675	60.7%
	3	13,403	34.4%	2,766	83.5%	16,623	39.3%
Medium General Service	4	1,186	46.9%	220	46.9%	1,406	46.9%
	5	286	11.3%	53	11.3%	339	11.3%
	6	200	7.9%	37	7.9%	237	7.9%
	7	529	20.9%	98	20.9%	627	20.9%
	8	329	13.0%	61	13.0%	390	13.0%
Large General Service	8	5	5.5%			5	3.4%
	9	46	50.5%	25	43.1%	71	48.0%
	10	39	42.9%	33	56.9%	72	48.6%
	12	1	1.1%				
High Demand General Service	12	10	100%			10	100%

*For Small General Service Customers, estimates of meters were obtained by applying percentages from the 1997 Network/Nonnetwork study and reaffirmed by the South Electrical Services Director. The numbers of meters of each service type for Large were estimated by using maximum kW as a proxy for max kVA.

8.4.2 Calculation of Meter Capital Costs

The assignment of capital costs to each customer group was based on the distribution in Table 8.14. Weighted meter capital costs are the sum of the percent of each meter configuration in the group times the cost of the configuration. The weighted cost was then annualized by multiplying by the discount factor to determine the annual payment over the life of the meter configuration. Meter capital costs are shown in **Tables 8.15a** and **8.15b.**

Table 8.15a

Meter Capital Costs by Customer Class (2004$)

	Residential	Small General Service	Medium General Service	Large General Service	High Demand General Service
Weighted Meter (1) Capital Costs	$41.71	$93.72	$372.41	$796.87	$3,351.73
Annualized Meter Capital Costs	$2.23	$5.77	$29.15	$50.34	$243.70

Table 8.15b

Meter Capital Costs by Customer Class (2004$)

	Residential		Small General Service		Medium General Service		Large General Service		High Demand General Service
	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	
Weighted Meter (1) Capital Costs	$41.71	$100.18	$89.16	$140.11	$400.93	$400.93	$752.41	$861.39	$3,351.73
Annualized Meter Capital Costs	$2.13	$5.11	$5.65	$7.15	$29.15	$20.45	$54.71	$43.95	$243.70

Some assumptions have been made in estimating meter capital costs. An approximate .26% reserve of Service Type 1 and 2 meters are maintained in stock at all times. As with transformers, that reserve is charged as part of the marginal meter costs. The presumed economic life of mechanical vs. solid state meters is different: for mechanical meters the economic life is 30 years; for solid state meters the economic life expectancy is 18 years. Residential and Network meters are all assumed to be mechanical; all others are assumed to be solid state.

As a result of the different economic lives, the discount factors for mechanical vs. solid state meters are also different: 0.051019 for mechanical meters; 0.072709 for solid state meters. The Annualized Meter Capital Costs for Medium and Large General Service classes was calculated by applying the discount factor for solid state meters (.072709) to Nonnetwork meters, and the discount factor for mechanical meters (.051019) to Network meters. The resulting figures were combined, then divided by the total meters in the class. (See Tables 8.15 and as part of the marginal meter costs.)

Assumptions:

- Inventory Reserve — 0.26% on Service types 1 and 2 only
- Economic Life (mechanical — 30 years for Residential and Network meters only meters)
- Economic Life state — 18 years for Nonresidential and Nonnetwork meters (solid meters)
- Discount Factor — 0.051019 for Residential and Network meters (mechanical meters)
- Discount Factor state — 0.072709 for Nonresidential and Nonnetwork meters (solid meters)
- Standard Interest Rate — 0.03

Tables 8.16a and **8.16b** integrate data from Tables 8.1a and 8.1b. The number of meters from Tables 8.1 is multiplied by the annual meter capital cost from Tables 8.15 to determine the total annual investment per customer class. The annual meter capital investment for the total system is derived by dividing the sum of individual class total annualized investment by the total number of meters. Class share percentages are based on the classes' proportions of annual investment in the total system.

Table 8.16a

Annual Meter Capital Investment by Class (2004$)

	Total (System)	Residential	Small General Service	Medium General Service	Large General Service	High Demand General Service
# of Meters	379,599	334,145	42,298	2,998	148	10
$/Meter/Year	$2.87	$2.23	$5.77	$29.15	$50.34	$243.70
Total Annualized Investment	$1,087,639	$746,405	$243,952	$87,394	$7,451	$2,437
Class Share of Annualized Investment	100.01%	68.63%	22.43%	8.04%	0.69%	0.22%

Table 8.16b

Annual Meter Capital Investment by Class (2004$)

	Total (System)	Residential		Small General Service		Medium General Service		Large General Service		High Demand General Service
		Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	
# of Meters	379,599	322,297	11,848	38,986	3,312	2,528	470	88	60	10
$/Meter/Year	$2.86	$2.13	$5.11	$5.65	$7.15	$29.15	$20.45	$54.71	$43.95	$243.70
Total Annualized Investment	$1,084,179	$686,493	$60,543	$220,271	$23,681	$73,691	$9,612	$4,814	$2,637	$2,437
Class Share of Annualized Investment	99.99%	63.32%	5.58%	20.32%	2.18%	6.80%	0.89%	0.44%	0.24%	0.22%

8.4.3 Operations and Maintenance Costs

Meter Operations Costs

Meter operation expenses are tallied in FERC Account 586 and in 2004 amounted to $1,563,286, including Social Security taxes. The total cost was allocated to individual classes based on each class's share of annual meter investment costs from Tables 8.16a and 8.16b. These costs by class were then divided by the number of meters per class from Tables 8.1a an 8.1b to compute a meter operation cost per meter for each customer class as shown in **Tables 8.17a** and **8.17b.**

Table 8.17a

Meter Operation Costs (2004$)

	Total (System)	Residential	Small General Service	Medium General Service	Large General Service	High Demand General Service
Class Share of Annual Meter Investment Costs	100.01%	68.63%	22.43%	8.04%	0.69%	0.22%
Class Share of Meter Operation Costs	$1,563,442	$1,072,883	$350,645	$125,688	$10,787	$3,439
Meters in Class	379,599	334,145	42,298	2,998	148	10
Meter Operation Cost per Meter	$4.12	$3.21	$8.29	$41.92	$72.89	$343.90

Table 8.17b

Meter Operation Costs (2004$)

	Total (System)	Residential		Small General Service		Medium General Service		Large General Service		High Demand General Service
		Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	
Class Share of Annual Meter Investment Costs	99.99%	63.32%	5.58%	20.32%	2.18%	6.80%	0.89%	0.44%	0.24%	0.22%
Class Share of Meter Operation Costs	$1,563,129	$989,873	$87,231	$317,660	$34,080	$106,303	$13,913	$6,878	$3,752	$3,439
Meters in Class	379,599	322,297	11,848	38,986	3,312	2,528	470	88	60	10
Meter Operation Cost per Meter	$4.12	$3.07	$7.36	$8.15	$10.29	$42.05	$29.60	$78.16	$62.53	$343.90

Meter Maintenance Costs

Meter maintenance expenses reported in FERC Account 597 equaled $16,345 in 2004. In prior years this amount was considerably higher (e.g., $335,882 in 1995). North Electrical Services staff , however, believe that with improvements in meter technology, maintenance requirements have been significantly reduced. The total meter maintenance costs were then allocated to customer classes in a fashion analogous to the procedure used in Tables 8.17. And in a similar fashion, these meter maintenance costs by class were divided by meters per class to produce estimates of maintenance costs per meter for each customer class as shown in **Tables 8.18a** and **8.18b.**

Table 8.18a

Meter Maintenance Costs
(2004$)

	Total (System)	Residential	Small General Service	Medium General Service	Large General Service	High Demand General Service
Class Share of Annual Meter Investment Cost	100.01%	68.63%	22.43%	8.04%	0.69%	0.22%
Class Share of Meter Maintenance Cost	$16,345	$11,218	$3,666	$1,314	$113	$36
Meters in Class	379,599	334,145	42,298	2,998	148	10
Meter Maintenance Cost per Meter	$0.04	$0.03	$0.09	$0.44	$0.76	$3.60

Table 8.18b

Meter Maintenance Costs
(2004$)

	Total (System)	Residential		Small General Service		Medium General Service		Large General Service		High Demand General Service
		Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	
Class Share of Annual Meter Investment Cost	99.99%	63.32%	5.58%	20.32%	2.18%	6.80%	0.89%	0.44%	0.24%	0.22%
Class Share of Meter Maintenance Cost	$16,345	$10,350	$912	$3,321	$356	$1,111	$145	$72	$39	$36
Meters in Class	379,599	322,297	11,848	38,986	3,312	2,528	470	88	60	10
Meter Maintenance Cost per Meter	$0.04	$0.03	$0.08	$0.09	$0.11	$0.44	$0.31	$0.82	$0.65	$3.60

Service Maintenance Costs

Service maintenance costs are allocated to customer classes according to the ratio of the total of these costs to the total capital costs of service connections. The first step in the calculation is the estimation of the total service maintenance costs themselves. The second step is the estimation of the total capital costs invested in service connections. These two values provide the numerator and the denominator of the allocator for the third step, the calculation of service maintenance costs per meter.

Total service maintenance costs are estimated on the basis of separating maintenance activities from other activities of certain work crews and adding certain materials costs. Three areas of service maintenance costs are included in customer costs:

1. service maintenance work performed by service crews is presented in Table 8.19 (which has two parts--South Electric Services and North Electric Services);
2. materials costs of the services replaced by the service crews is developed in Tables 8.20a and 8.20b, and 8.21a and 8.21b; and
3. the portion of the work done by line crews that can be assigned to routine maintenance, conversions and services to the service "drop” is presented in Tables 8.22a and 8.22b.

The total service maintenance costs are then allocated to customer classes in proportion to estimates of the capital costs invested in service connections. Tables 8.23a and 8.23b, and 8.24a and 8.24b develop estimates of the investment cost to replace the various services described in Table 8.13. Those costs by service type are then aggregated into total investment costs by customer type in Tables 8.24. Average investment cost per meter by customer type is then developed in Tables 8.25a and 8.25b**,** along with a ratio for the entire system of (service-related maintenance) / (total service investment cost). Tables 8.26a and 8.26b then combine this ratio with the average investment per meter for each customer type to derive the average service maintenance cost for each customer class.

Service Maintenance Activities

The three categories that make up service maintenance costs are: service maintenance labor performed by service crews, routine maintenance to the service "drop" (labor and materials) provided by line crews, and service maintenance materials (that is, materials cost of services replaced).

The service activities performed by the service crews were logged in monthly activity reports. The customer-related maintenance activities on the service drop include replacement of service drops for maintenance and trouble calls for maintenance on the service In 2004 there were no Trouble Calls (billed service calls for customers) and no P-65 Service Calls (for low-income customers) logged by service crews. As of March, 2004, this data was no longer maintained by South Electrical Services. Thus, 2003 figures which South Electrical Services provided (in a 2004 cost-of-service study) were adjusted by the same percentages that the North Electrical Services changed.

The activity reports provide a way to estimate the number of each of these activities (replacement of service drops and maintenance on the service) during the year which are then multiplied by average crew time. This is multiplied by the hourly transport cost and hourly labor cost for each crew to estimate total transportation cost and total labor cost for each activity. These two items are added to get total cost for each activity. **Table 8.19** presents the data on service maintenance costs for the South and North Service Centers, at a labor cost of $498,162.

Table 8.19

Service Maintenance Activity
2004 Activity and 2004$
South Electrical Services

	Number	Hours/ Events	Total Crew Hours	Hourly Labor Cost	Hourly Transport Cost	Total Labor Cost	Total Transport Cost	Subtotal Cost	Total Service Cost
DAY SHIFT:									
Avg Crew=2 Lineworkers									
Services Replaced	32	1.00	32.00	$141.86	$9.88	$4,540	$316	$4,856	$4,856
Service Calls									
Billed	0	0.75	0.00	$141.86	$9.88	$0	$0	$0	$0
Unbilled	1,607	0.75	1205.25	$141.86	$9.88	$170,977	$11,908	$182,885	$182,885
P-65	0	0.75	0.00	$141.86	$9.88	$0	$0	$0	$0
SWING & GRAVEYARD SHIFT:									
Avg Crew=2 Lineworkers									
Service Calls									
Billed	0	0.75	0.00	$141.86	$9.88	$0	$0	$0	$0
Unbilled	775	0.75	581.25	$141.86	$9.88	$82,456	$5,743	$88,199	$88,199
P-65	0	0.75	0.00	$141.86	$9.88	$0	$0	$0	$0
Total for South									**$275,939**

Table 8.19

Service Maintenance Activity
2004 Activity and 2004$
North Electrical Services

	Number	Hours/ Events	Total Crew Hours	Hourly Labor Cost	Hourly Transport Cost	Total Labor Cost	Total Transport Cost	Subtotal Cost	Total Service Cost
DAY SHIFT:									
Avg Crew=2 Lineworkers									
Services Replaced	161	1.00	161.00	$141.86	$9.88	$22,839	$1,591	$24,430	$24,430
Service Calls									
Billed	0	0.75	0.00	$141.86	$9.88	$0	$0	$0	$0
Unbilled	906	0.75	679.50	$141.86	$9.88	$96,394	$6,713	$103,107	$103,107
P-65	0	0.75	0.00	$141.86	$9.88	$0	$0	$0	$0
SWING & GRAVEYARD SHIFT:									
Avg Crew=2 Lineworkers									
Service Calls									
Billed	0	0.75	0.00	$141.86	$9.88	$0	$0	$0	$0
Unbilled	832	0.75	624.00	$141.86	$9.88	$88,521	$6,165	$94,686	$94,686
P-65	0	0.75	0.00	$141.86	$9.88	$0	$0	$0	$0
Total for North									**$222,223**

Material Costs

Table 8.20 contains the cost of service “drop” materials for the different service types. These costs range from $145 for a single phase, 125-ampere service to $169,489 for a three phase, 2400 ampere 13.8 kV and 20,000 kVA service. **Tables 8.21a and 8.21b** contain estimates of service "drop" materials cost by customer type. These costs are derived from the materials cost by type of service from Table 8.20 weighted by the distribution of types of services by types of customers from Tables 8.14a and 8.14b multiplied by the number of services replaced for each customer class. This latter number equals each class's share (in terms of percent of all meters) of the total number of overhead services replaced (Table 8.19).

Table 8.20

Cost of Service Drop Materials by Service Type (2004$)

	Service #1 Single Phase 125 amp	Service #2 Single Phase 225 amp	Service #3 Three Phase 225 amp	Service #4 Three Phase 400 amp w/CT w/demand mtr.	Service #5 3 phase-400 amp 277/480V 300 max kVA w/demand meter w/o reactive mtr	Service #6 3 phase-800 amp 277/480V 665 max kVA w/demand meter w/o reactive mtr	Service #7 3 phase-400 amp 277/480V 300 max kVA w/demand meter w/reactive meter	Service #8 3 phase -800 amp 277/480V 665 max kVA w/demand meter w/reactive meter
Hardware								
Customer End	$15.00	$8.00	$10.00	$10.00	$61.00	$71.00	$10.00	$71.00
City Light End	$15.00	$21.00	$26.00	$26.00	$49.00	$77.00	$26.00	$77.00
Conductor (per ft)	$0.77	$0.92	$1.64	$1.64	$2.63	$5.25	$2.63	$5.25
Conductor (per 150 ft)	$115.50	$138.00	$246.00	$246.00	$394.50	$787.50	$394.50	$787.50
Total	$145.50	$167.00	$282.00	$282.00	$504.50	$935.50	$430.50	$935.50

	Service #9 3 phase-2400 amp 277/480V 1995 max kVA w/TOU register w/reactive meter Nonnetwork	Service #9 3 phase-2400 amp 277/480V 1995 max kVA w/TOU register w/reactive meter Network	Service #10 3 phase-600 amp 7.97/13.8 kV 7500 max kVA w/TOU register w/reactive meter Nonnetwork	Service #10 3 phase-600 amp 277/480V 8500 max kVA w/TOU register w/reactive meter Network	Service #11 3 phase-3000 amp 4kV 10,000 kVA w/TOU Register w/reactive meter Nonnetwork	Service #12 3 phase 2400 amp 13.8 kV 20,000 kVA w/TOU register w/reactive meter Nonnetwork
Hardware						
Customer End	N/A	N/A	N/A	N/A	N/A	N/A
City Light End	N/A	N/A	N/A	N/A	N/A	N/A
Conductor (per ft)	N/A	N/A	N/A	N/A	N/A	N/A
Conductor (per 150 ft)	N/A	N/A	N/A	N/A	N/A	N/A
Total	**$ 33,299.00**	**$ 33,279.00**	**$ 45,189.00**	**$ 151,252.00**	**$ 39,367.73**	**$ 169,488.89**

Table 8.21a Service Maintenance Costs Total Service Drop Materials Costs by Customer Class (2004$)						
	Total (System)	Residential	Small General Service	Medium General Service	Large General Service	High Demand General Service
Meters in Class	379,599	334,145	42,298	2,998	148	10
Class Proportion	100.00%	88.03%	11.14%	0.79%	0.04%	0.003%
Services Replaced Service Crews	193	169.89	21.51	1.52	0.08	0.01
Weighted Cost of Materials for Service Replacement		$157	$211	$475	$62,515	$169,489
Total Materials Costs for Services Replaced	$37,563	$26,737	$4,536	$724	$4,704	$862

Table 8.21b Service Maintenance Costs Total Service Drop Materials Costs by Customer Class (2004$)										
	Total System	Residential		Small General Service		Medium General Service		Large General Service		High Demand General Service
		Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	
Meters in Class	379,599	322,297	11,848	38,986	3,312	2,528	470	88	60	10
Class Proportion	100.00%	84.90%	3.12%	10.27%	0.87%	0.67%	0.12%	0.023%	0.016%	0.003%
Services Replaced Service Crews	193	163.87	6.02	19.82	1.68	1.29	0.24	0.04	0.03	0.01
Weighted Cost of Materials for Service Replacement		$157	$157	$207	$263	$475	$475	$36,683	$100,402	$169,489
Total Materials Costs for Services Replaced	$37,563	$25,789	$948	$4,094	$442	$610	$113	$1,641	$3,063	$862

Routine Maintenance

In addition to maintenance activities by service crews, there are routine replacement activities performed by crews as part of the work on the overhead and underground system. An estimated 10 percent of the budget expenditures for routine maintenance and service activities of line crews (Projects 4280 and 4282, Organizational Units 342 and 351) is estimated to be related to maintenance of the service drop and is included in the service maintenance costs. For 2004, $327,823 from the line crews' budget and $156,059 for network service, totaling $483,882 is included in service maintenance costs and is shown in **Tables 8.22a and 8.22b.**

Total Maintenance Costs

Total maintenance costs for the customer service drop are summarized in Tables 8.22a and 8.22b. A combined Network-Nonnetwork total of $1,019,607 is calculated for routine maintenance of service drops, material costs, and service maintenance activities for 2004.

Table 8.22a

Service Maintenance Costs
Annual Costs for Service Drop
Maintenance, Labor & Materials
(2004$)

Service Maintenance Labor[1]	$ 498,162
Service Maintenance Materials[2]	$ 37,563
Routine Maintenance Labor and Materials (line crew)[3]	$ 483,882
TOTAL	$ 1,019,607

[1]Table 8.19a
[2]Table 8.21a
[3]Text

Table 8.22b

Service Maintenance Costs
Annual Costs for Service Drop
Maintenance, Labor & Materials
(2004$)

	Nonnetwork	Network
Service Maintenance Labor[1]	$ 498,162	$ -
Service Maintenance Materials[2]	$32,997	$4,566
Routine Maintenance Labor and Materials (line crew)[3]	$ 327,823	$ 156,059
TOTAL	$ 858,982	$ 160,625

[1] Table 8.19b
[2] Table 8.21b
[3] Text

Allocation of Service Maintenance Costs

Service maintenance costs were allocated to customer classes based on the ratio of customer-related service maintenance costs to the total investment in service connections. This ratio is applied to the service connection cost of each customer to obtain the service maintenance cost per customer in each class. Tables 8.23 through 8.25 contain information used to allocate service maintenance costs to customer classes and per customer within customer classes.

Table 8.23 shows the estimated investment costs, including materials and labor, for each of the twelve service types. These are the costs that would be added to the Department's capital plant accounts if all services were installed using the types of services shown here. Service connection costs shown in Table 8.23, except for Services 9 through 12, are taken from the Departmental Policy and Procedures Manual (500 P III-417, Schedule 100, Table 2.1, January 20, 2004). Service connection costs for the generic large service types (9, 10, 11 and 12) are estimates made by Customer Engineering and Network Engineering staff based on recent (2004) service connections.

Table 8.23

Service Maintenance Costs
Investment Costs by Service Type
(2004$)

	Service #1 Single Phase 125 amp	Service #2 Single Phase 225 amp	Service #3 Three Phase 225 amp	Service #4 Three Phase 400 amp w/CT w/demand mtr.	Service #5 3 phase-400 amp 277/480V 300 max kVA w/demand meter w/o reactive mtr	Service #6 3 phase-800 amp 277/480V 665 max kVA w/demand meter w/o reactive mtr	Service #7 3 phase-400 amp 277/480V 300 max kVA w/demand meter w/reactive meter	Service #8 3 phase -800 amp 277/480V 665 max kVA w/demand meter w/reactive meter
Materials	$145.50	$167.00	$282.00	$282.00	$504.50	$935.50	$430.50	$935.50
Labor *	$347.00	$347.00	$407.00	$948.00	$1,808.00	$2,206.00	$1,808.00	$2,206.00
Total	$492.50	$514.00	$689.00	$1,230.00	$2,312.50	$3,141.50	$2,238.50	$3,141.50

	Service #9 3 phase-2400 amp 277/480V 1995 max kVA w/TOU register w/reactive meter Nonnetwork	Service #9 3 phase-2400 amp 277/480V 1995 max kVA w/TOU register w/reactive meter Network	Service #10 3 phase-600 amp 7.97/13.8 kV 7500 max kVA w/TOU register w/reactive meter Nonnetwork	Service #10 3 phase-600 amp 277/480V 8500 max kVA w/TOU register w/reactive meter Network	Service #11 3 phase-3000 amp 4kV 10,000 kVA w/TOU Register w/reactive meter Nonnetwork	Service #12 3 phase 2400 amp 13.8 kV 20,000 kVA w/TOU register w/reactive meter Nonnetwork
Materials	$33,299	$33,279	$45,189	$151,252	$39,368	$169,489
Labor	$15,979	$76,603	$18,196	$248,772	$27,192	$55,840
Total	$49,278	$109,882	$63,385	$400,024	$66,559	$225,329

[1] Table 8.20 from DPP P III-417, Schedule 100 for Service # 1-8

Tables 8.24a and **8.24b** show how the total investments in service connection are calculated based on the distribution of service types by customer class and their related costs.

Table 8.24a

Service Maintenance Costs
Total Investment by Customer Class
in Service Connections
(2004$)

	Number of Meters[1] (A)	Service Type (B)	Percent Distribution[2] (C)	Unit Cost[3] (D)	Total Investment[4] (E)	% of Total
Residential	334,145	1	49.6%	$ 493	$81,544,456	
		2	49.6%	$ 514	$85,104,265	
		3	0.9%	$ 689	$2,067,000	
					$168,715,721	**76.36%**
Small General Service	42,298	2	60.7%	$ 514	$13,196,891	
		3	39.3%	$ 689	$11,453,326	
					$24,650,217	**11.16%**
Medium General Service	2,998	4	46.9%	$ 1,230	$1,729,456	
		5	11.3%	$ 2,313	$783,415	
		6	7.9%	$ 3,142	$744,039	
		7	20.9%	$ 2,239	$1,403,275	
		8	13.0%	$ 3,142	$1,225,310	
					$5,885,495	**2.66%**
Large General Service	148	8	3.4%	$3,142	$15,708	
		9	48.0%	$ 74,609	$5,297,239	
		10	48.6%	$ 196,378	$14,139,216	
					$19,452,163	**8.80%**
High Demand General Service	10	12	100%	$ 225,329	**$2,253,288**	**1.02%**
TOTAL	379,599				**$220,956,884**	**100.00%**

[1] Table 8.1a
[2] Table 8.14
[3] Table 8.23
[4] (A) * (C) * (D)

Table 8.24b

Service Maintenance Costs
Total Investment by Customer Class
in Service Connections
(2004$)

	Number of Meters[1] (A)	Service Type (B)	Percent Distribution[2] (C)	Unit Cost[3] (D)	Total Investment[4] (E)	% of Total
Residential:						
Nonnetwork	322,297	1	49.6%	$ 493	$78,653,081	
		2	49.6%	$ 514	$82,086,667	
		3	0.9%	$ 689	$1,993,709	
					$162,733,456	**73.14%**
Network	11,848	1	49.6%	$ 493	$2,894,229	
		2	49.5%	$ 514	$3,014,487	
		3	0.8%	$ 689	$68,900	
					$5,977,616	**2.69%**
Small General Service:						
Nonnetwork	38,986	2	65.6%	$ 514	$13,145,455	
		3	34.4%	$ 689	$9,240,306	
					$22,385,761	**10.06%**
Network	3,312	2	16.5%	$ 514	$280,891	
		3	83.5%	$ 689	$1,905,443	
					$2,186,334	**0.98%**
Medium General Service:						
Nonnetwork	2,528	4	46.9%	$ 1,230	$1,458,327	
		5	11.3%	$ 2,313	$660,598	
		6	7.9%	$ 3,142	$627,395	
		7	20.9%	$ 2,239	$1,183,282	
		8	13.0%	$ 3,142	$1,033,217	
					$4,962,819	**2.23%**
Network	470	4	46.9%	$ 1,230	$271,129	
		5	11.3%	$ 2,313	$122,817	
		6	7.9%	$ 3,142	$116,644	
		7	20.9%	$ 2,239	$219,993	
		8	13.0%	$ 3,142	$192,093	
					$922,676	**0.41%**
Large General Service:						
Nonnetwork	88	8	5.5%	$ 3,142	$15,190	
		9	50.5%	$ 49,278	$2,192,077	
		10	42.9%	$ 63,385	$2,390,532	
					$4,582,609	**2.06%**
Network	60	8	0.0%	$ 3,142	$0	
		9	43.1%	$ 109,882	$2,841,766	
		10	56.9%	$ 400,024	$13,655,991	
					$16,497,757	**7.41%**
High Demand General Service:						
Nonnetwork	10	12	100.0%	$ 225,329	**$2,253,288**	**1.01%**
TOTAL	379,599				**$222,502,317**	**100.00%**

[1] Table 8.1a
[2] Table 8.14
[3] Table 8.23
[4] (A) * (C) * (D)

In **Tables 8.25a** and **8.25b,** the ratio of annual service maintenance costs to total investment (at current prices) in service connections is calculated from corresponding totals in Tables 8.22 and 8.24, respectively. Also shown is the average service connection investment per customer.

Table 8.25a

**Service Maintenance Costs
Total Investment by Customer Class
in Service Connections
(2004$)**

	Total (System)	Residential	Small General Service	Medium General Service	Large General Service	High Demand General Service
Total Investment	$220,956,884	$168,715,721	$24,650,217	$5,885,495	$19,452,163	$2,253,288
Number of Meters	379,599	334,145	42,298	2,998	148	10
Average Investment per meter	$582.08	$504.92	$582.78	$1,963.14	$131,433.53	$225,328.79
B. Service-Related Maintenance (System)			$1,019,607			
C. Ratio of Service-Related Maintenance Expense to Service Investment			$1,019,607 / $220,956,884	=	**0.004615**	

Table 8.25b

**Service Maintenance Costs
Total Investment by Customer Class
in Service Connections
(2004$)**

	Total System	Residential		Small General Service		Medium General Service		Large General Service		High Demand General Service
		Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	
Total Investment	$222,502,317	$162,733,456	$5,977,616	$22,385,761	$2,186,334	$4,962,819	$922,676	$4,582,609	$16,497,757	$2,253,288
Number of Meters	379,599	322,297	11,848	38,986	3,312	2,528	470	88	60	10
Average Investment	$586.15	$504.92	$504.53	$574.20	$660.13	$1,963.14	$1,963.14	$52,075.10	$274,962.62	$225,328.79
B. Service-Related Maintenance (System)			$1,019,607							
C. Ratio of Service-Related Maintenance Expense to Service Investment			$1,019,607 / $222,502,317	=	**0.004582**					

Tables 8.26a and **8.26b** derive an estimate of service maintenance costs per meter by customer class. The maintenance investment ratio is multiplied by the average service investment cost per meter in each customer class to get the average service maintenance cost per meter for the class. Results from Table 8.26b are used in deriving total cost of Service Drop O&M in Table 7.10 in Chapter 7. Those results, in turn, are a component of deriving total cost and cost shares for allocating revenue requirements for Wires and Related Equipment in Table 7.11 in that chapter.

Table 8.26a

Service Maintenance Costs
Average Service Maintenance Costs
per Meter by Customer Class
(2004$)

	Total (System)	Residential	Small General Service	Medium General Service	Large General Service	High Demand General Service
Average Service Investment per Meter	$582.08	$504.92	$582.78	$1,963	$131,434	$225,329
Maintenance-to-Investment Ratio	0.004615	0.004615	0.004615	0.004615	0.004615	0.004615
Service Maintenance Cost per Meter	$2.69	$2.33	$2.69	$9.06	$606.50	$1,039.78

Table 8.26b

Service Maintenance Costs
Average Service Maintenance Costs
per Meter by Customer Class
(2004$)

	Total System	Residential		Small General Service		Medium General Service		Large General Service		High Demand General Service
		Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	
Average Service Investment per Meter	$586.15	$504.92	$504.53	$574.20	$660.13	$1,963	$1,963	$52,075	$274,963	$225,329
Maintenance-to-Investment Ratio	0.004582	0.004582	0.004582	0.004582	0.004582	0.004582	0.004582	0.004582	0.004582	0.004582
Service Maintenance Cost per Meter	$2.69	$2.31	$2.31	$2.63	$3.02	$9.00	$9.00	$238.63	$1,260.00	$1,032.56

8.4.4 Summary of Meter and Service Drop Costs

Tables 8.27a and **8.27b** summarize meter and service drop costs described in Chapter 8. Costs are in 2004 dollars and are expressed in terms of cost per meter. The meter-related costs from Table 8.27b are used in developing cost shares for meter-related revenue requirements in Table 7.12 in Chapter 7. For instance, the total cost for residential nonnetwork customers from Table 8.27b is $7.55 per meter. Service maintenance costs for those customers are $2.31 per meter. Thus, the direct meter-related costs for these customers is 7.55 – 2.31 = 5.24, which is the cost per meter used in Table 7.12.

Table 8.27a

Marginal Meter and Service Drop Costs by Customer Class (2004$)

	Residential	Small General Service	Medium General Service	Large General Service	High Demand General Service
Annual Capital Costs:					
Meters[1]	$2.23	$5.77	$29.15	$50.34	$243.70
Annual O&M Costs:					
Meter Operation[2]	$3.21	$8.29	$41.92	$72.89	$343.90
Meter Maintenance[3]	$0.03	$0.09	$0.44	$0.76	$3.60
Service Maintenance[4]	$2.33	$2.69	$9.06	$606.50	$1,039.78
Total O&M	$5.57	$11.07	$51.42	$680.15	$1,387.28
Total Meter & Service Drop Costs per meter	**$7.81**	**$16.83**	**$80.57**	**$730.50**	**$1,630.98**

[1] Table 8.15a
[2] Table 8.17a
[3] Table 8.18a
[4] Table 8.26a

Table 8.27b

Marginal Meter and Service Drop Costs by Customer Class (2004$)

	Residential		Small General Service		Medium General Service		Large General Service		High Demand General Service
	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	Nonnetwork	Network	
Annual Capital Costs:									
Meters[1]	$2.13	$5.11	$5.65	$7.15	$29.15	$20.45	$54.71	$43.95	$243.70
Annual O&M Costs:									
Meter Operation[2]	$3.07	$7.36	$8.15	$10.29	$42.05	$29.60	$78.16	$62.53	$343.90
Meter Maintenance[3]	$0.03	$0.08	$0.09	$0.11	$0.44	$0.31	$0.82	$0.65	$3.60
Service Maintenance[4]	$2.31	$2.31	$2.63	$3.02	$9.00	$9.00	$238.63	$1,260.00	$1,032.56
Total O&M	$5.42	$9.75	$10.87	$13.42	$51.49	$38.91	$317.61	$1,323.19	$1,380.06
Total Meter & Service Drop Costs per meter	**$7.55**	**$14.86**	**$16.52**	**$20.57**	**$80.64**	**$59.36**	**$372.32**	**$1,367.14**	**$1,623.76**

[1] Table 8.15b
[2] Table 8.17b
[3] Table 8.18b
[4] Table 8.26b

8.5 Derivation of Cost Shares: Customer Costs

Table 8.28 uses the customer cost data from Table 8.12b to derive the cost shares for Customer Cost Revenue Requirements. Similar to the development of estimated costs in 2007 and 2008 for Service Drops in Table 7.10 in the previous chapter, Table 8.28 lists the projected number of meters by nonnetwork and network classes from Table 5.9 in Chapter 5 plus the marginal customer costs per meter from Table 8.12b. The bottom portion of the table presents the total cost of customer costs as the product of projected number of meters and the per-meter customer costs by class for nonnetwork and network customers. These costs are, initially, in $2004, which are then converted to dollars for each of the two forecast years. Then the shares of the total service-area cost associated with each customer class in the nonnetwork and network areas are in the last row of each of the bottom portions of the table. Shares used to allocate the sum of revenue requirements for 2007 and 2008 are derived by adding the total marginal costs for each those years and dividing by the sum of costs for the total service territory.

Table 8.28
Derivation of Cost Shares for Customer Cost Revenue Requirements

Meters	Total Nonnetwork (EXcludes Network Residential & Small)						
	Total	Residential	Small	Medium	Large	High Demand	Lights
2007	370,540	328,228	39,712	2,500	89	11	N/A
2008	372,689	330,177	39,912	2,500	89	11	N/A

Meters	Downtown Network				
	Total	Residential	Small	Medium	Large
2007	16,298	12,445	3,303	493	57
2008	16,349	12,496	3,303	493	57

	2004$/meter/year					
Customer Costs	Residential	Small	Medium	Large	High Demand	Lights
Nonnet	94.91	73.95	212.13	11,440.00	35,064.00	N/A
Net	119.22	88.28	166.75	3,246.00		

Cost Adjustments:	$ 2007 = 1.08485	$ 2008 = 1.11414

Capital + O&M Cost	Total Nonnetwork (EXcludes Network Residential & Small)						
	Total	Residential	Small	Medium	Large	High Demand	Lights
2007	36,023,011	31,152,119	2,936,702	530,325	1,018,160	385,704	N/A
$2007	39,079,611	33,795,418	3,185,885	575,324	1,104,552	418,431	
Share of Svc Terr.	94.634%	81.838%	7.715%	1.393%	2.675%	1.013%	0.000%

	Downtown Network					Svc Terr
	Total	Residential	Small	Medium	Large	Total
2007	2,042,511	1,483,693	291,589	82,208	185,022	38,065,522
$2007	2,215,821	1,609,586	316,331	89,183	200,721	41,295,432
Share of Svc Terr.	5.366%	3.898%	0.766%	0.216%	0.486%	100.000%

	Total Nonnetwork (EXcludes Network Residential & Small)						
	Total	Residential	Small	Medium	Large	High Demand	Lights
2008	36,222,780	31,337,099	2,951,492	530,325	1,018,160	385,704	N/A
$2008	40,357,332	34,913,988	3,288,383	590,858	1,134,375	429,729	
Share of Svc Terr.	94.647%	81.881%	7.712%	1.386%	2.660%	1.008%	0.000%

	Downtown Network					Svc Terr
	Total	Residential	Small	Medium	Large	Total
2008	2,048,592	1,489,773	291,589	82,208	185,022	38,271,372
$2008	2,282,423	1,659,819	324,871	91,591	206,141	42,639,755
Share of Svc Terr.	5.353%	3.893%	0.762%	0.215%	0.483%	100.000%

	Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)						
	Total	Residential	Small	Medium	Large	High Demand	Lights
2007+'08	$ 79,436,944	$ 68,709,406	$ 6,474,268	$ 1,166,181	$ 2,238,927	$ 848,161	$ -
Share of Svc Terr.	94.641%	81.860%	7.713%	1.389%	2.667%	1.010%	0.000%

	Downtown Network					Total Svc Terr.
	Total	Residential	Small	Medium	Large	Nonnet+Net
2007+'08	$ 4,498,244	$ 3,269,405	$ 641,202	$ 180,774	$ 406,862	$ 83,935,188
Share of Svc Terr.	5.359%	3.895%	0.764%	0.215%	0.485%	100.000%

Chapter 9

Summary of Marginal Cost Shares and Allocation of Revenue Requirements by Shares

9.1 Functional Revenue Requirements

Table 9.1 presents the sum of the functionalized revenue requirements for 2007 and 2008 as developed in the ***2007-2008 Revenue Requirements Analysis***. Table 9.1 (which is the same as Table 2.2) illustrates how the total revenue requirements by functional category are derived. The explanation behind the derivation is in the ***2007-2008 RRA***. The information needed for purposes here, though, is just the first column of numbers, i.e., the total revenue requirements by function. Note that two of the revenue requirements, Wires and Related Equipment and Transformers, have allocations separated between nonnetwork and network customers. For future reference, recall that the downtown network comprised 85 percent of the total network load recently. Hence, when the network revenue requirements for these two categories are allocated to downtown network customers, the network totals in Table 9.1 are multiplied by 85 percent and the result is allocated by network shares developed here. The 85 percent network result is then subtracted from the total for both nonnetwork and network revenue requirements and this result is assigned to nonnetwork customers for purposes of allocating nonnetwork revenue requirements.

Another important note is that net wholesale revenues to be received by City Light are so much greater than they have been in the past that they distort actual energy costs by a significant amount. They have, therefore, been removed from the unbundling process and are allocated to customer classes after all other cost of service allocations have been made by marginal cost shares. The next two paragraphs give further explanation about this treatment of net wholesale revenue and are taken directly from Chapter 7 of the ***2007-2008 RRA***.

The rationale for allocating net wholesale revenues to customer classes after other cost allocations have been determined, and in fact based on those prior allocations, is that the risk City Light faces through sales and purchases of energy in the West Coast wholesale market is borne by the utility as a whole—that is, all functions and all customer classes. City Light's participation in the wholesale market involves substantial risk because the utility's energy supply is determined by unpredictable weather conditions and by prices that are also subject to significant uncertainty. New, stricter financial policies were adopted by the City Council in 2001 and 2005 (Resolutions 30428 and 30761) with the goal of managing the risk associated with the possible wide variance of wholesale revenue and assuring the utility's financial strength over the long term by reducing its debt.

Prior to the energy crisis of 2000-2001, City Light's participation in the wholesale market was fairly small. In 2000 and 2001, purchases on that market exceeded sales by a significant amount. By 2002, however, City Light had acquired new resources and sales began to exceed purchases by a very large amount, with this situation continuing through 2005, into 2006, and through the forecast horizon. If City Light had continued with its prior policy of allocating net wholesale revenue (which was negative, i.e., an addition to power expense, in the years 1992-1995, 1998 and 2000-2001) to the purchased power function of the 2007 unbundled revenue requirement, the expected $178 million of net revenue in this category would have reduced the power portion of the revenue requirement by 42%. Such a reduction would disproportionately benefit energy-intensive customers through rates, to the detriment of those which are not so energy-intensive, when the financial risk of net wholesale revenues being significantly different from the forecast is really borne equally by all the utility's customer-owners

9.2 Marginal Cost Shares

Table 9.2 presents a summary from the previous chapters of the total marginal costs by class for nonnetwork and network customers for the functional categories of the revenue requirements. This table is formatted to be compatible with the functionalized revenue requirements presented in Table 9.1. One set of marginal costs is used to allocate each of the four components of Energy revenue requirements. The other itemized revenue requirements have their own set of marginal cost shares used for allocation purposes. The table indicates the sources from the previous chapters of all the marginal cost data. The values in the table equal the sum of marginal costs for 2007 and 2008.

As mentioned previously, the revenue requirement associated with the general subsidy provided for low-income residential customers is allocated by the shares derived from the sum of all other measured marginal costs. Hence, the last row in Table 9.2 develops these shares.

Table 9.3, in the same general format as the previous two tables, presents a summary of the marginal cost shares used to allocate revenue requirements.[25] These data also pertain to the shares based on the sum of marginal costs for 2007 and 2008. The table indicates the sources for all the data but, of course, the results can be derived from the cost data in Table 9.2. As mentioned, two of the revenue requirements, Wires and Related Equipment and Transformers, are separated initially between nonnetwork and network customers. Hence, shares for these two categories of revenue requirements are based on shares *conditional upon* nonnetwork or network status.

[25] The table shows results rounded to the nearest one-thousandth of one percent. Actual calculations use results that have greater precision.

Table 9.1
Functionalized Revenue Requirements, 2007 + 2008

	Total excluding Net Whlsale	Direct Expenses	Revenue Offsets & Additions	Direct Expenses (Net)	Depreciation and Amortization	Capital Contributions and Grants	Interest	Admin. and General	Rev. Taxes & County Payments	Net Income	Net Wholesale Revenue	Total Revenue Req'm't
Total Energy	**962,241,599**	**615,471,520**	**(62,230,806)**	**553,240,714**	**52,766,404**	**(1,274,040)**	**46,565,073**	**29,298,035**	**82,629,406**	**199,016,006**	**(206,146,912)**	
Power	819,642,791	521,457,645	(52,624,731)	468,832,914	38,195,561	0	31,790,590	25,300,597	69,349,842	186,173,287	(171,294,209)	
Conservation	35,697,234	4,910,905	(600,000)	4,310,905	8,734,564	0	9,700,730	1,728,518	2,790,160	8,432,358	(7,333,288)	
Transmission-Long Distance	106,901,573	89,102,970	(9,006,075)	80,096,895	5,836,280	(1,274,040)	5,073,754	2,268,920	10,489,404	4,410,360	(27,519,415)	
Total Retail Services	**476,264,787**	**171,654,328**	**(34,367,780)**	**137,286,548**	**133,119,533**	**(51,234,629)**	**69,969,478**	**83,782,656**	**42,520,241**	**60,820,961**	**(111,453,710)**	
Total Distribution	335,489,615	95,146,737	(24,375,626)	70,771,111	108,317,517	(51,234,629)	67,068,692	53,895,353	28,372,116	58,299,454	(74,262,896)	
Transmission-In Service Area	*19,525,639*	*7,697,464*	*(829,710)*	*6,867,754*	*3,980,305*	*(638,465)*	*2,166,991*	*3,460,168*	*1,805,228*	1,883,657	(4,753,629)	
Stations	*65,023,271*	*23,727,644*	*(2,079,702)*	*21,647,942*	*10,373,458*	*(68,327)*	*6,374,135*	*15,068,105*	*6,087,242*	5,540,716	(15,994,886)	
Wires and Related Equipment	*172,220,352*	*46,134,284*	*(22,101,787)*	*24,032,497*	*70,171,417*	*(42,361,017)*	*43,364,612*	*25,546,147*	*13,772,012*	37,694,684	(35,915,804)	
non-network	*121,050,282*	*39,188,649*	*(19,075,412)*	*20,113,238*	*44,626,227*	*(26,939,920)*	*27,578,166*	*21,762,215*	*9,938,039*	23,972,318	(25,932,095)	
network	*51,170,070*	*6,945,634*	*(3,026,375)*	*3,919,259*	*25,545,190*	*(15,421,097)*	*15,786,446*	*3,783,932*	*3,833,973*	13,722,366	(9,983,709)	
Transformers	*37,491,557*	*2,749,205*	*635,573*	*3,384,778*	*16,548,180*	*(7,641,140)*	*11,062,273*	*1,668,348*	*2,853,237*	9,615,880	(7,468,750)	
non-network	*20,492,381*	*843,521*	*635,573*	*1,479,094*	*9,590,046*	*(4,428,214)*	*6,410,838*	*340,861*	*1,527,135*	5,572,620	(3,996,896)	
network	*16,999,177*	*1,905,684*	*0*	*1,905,684*	*6,958,135*	*(3,212,926)*	*4,651,435*	*1,327,487*	*1,326,102*	4,043,259	(3,471,854)	
Streetlights/Floodlights	*19,818,233*	*8,719,727*	*0*	*8,719,727*	*3,198,615*	*(525,681)*	*1,390,742*	*3,921,484*	*1,904,442*	1,208,902	(5,002,714)	
Meters	*21,410,562*	*6,118,413*	*0*	*6,118,413*	*4,045,541*	*0*	*2,709,939*	*4,231,101*	*1,949,955*	2,355,614	(5,127,113)	
Customer Accounts & Services	122,578,426	62,064,848	(9,765,301)	52,299,548	23,924,076	0	2,798,104	28,829,354	12,295,092	2,432,251	(32,320,367)	
Low-Income Assistance	18,196,747	14,442,743	(226,853)	14,215,889	877,939	0	102,682	1,057,948	1,853,032	89,256	(4,870,447)	
Total	**1,438,506,386**	**787,125,848**	**(96,598,586)**	**690,527,262**	**185,885,937**	**(52,508,669)**	**116,534,551**	**113,080,691**	**125,149,647**	**259,836,967**	**(317,600,622)**	**1,120,905,764**
Load (MWh)	**19,173,617**											
Average Cost per MWh	$75.025	$41.053	($5.038)	$36.014	$9.695	($2.739)	$6.078	$5.898	$6.527	$13.552	($16.564)	$58.461
Percent of Total Cost	100.00%	54.72%	-6.72%	48.00%	12.92%	-3.65%	8.10%	7.86%	8.70%	18.06%	-22.08%	77.92%

Table 9.2
Summary of Marginal Costs by Functional Category, 2007+ 2008
And Development of Cost Shares for Service Area Total Marginal Cost

	Service Territory	Total Nonnetwork (EXcludes Network Residential & Small)							Source
		Total	Residential	Small	Medium	Large	High Demand	Lights	
Energy	1,612,306,107	1,382,010,342	530,559,199	179,593,634	313,437,994	151,078,403	191,935,057	15,406,055	Table 6.7
Production									
Purchased Power									
Transmission - Long Distance									
Conservation									
Retail Service	284,681,367	196,834,410	121,557,741	22,012,027	27,385,162	13,352,679	11,587,876	743,142	
Total Distribution	200,746,179	117,397,466	52,848,335	15,537,759	26,218,981	11,113,752	10,739,715	743,142	
- Transmission - In Service Area	29,334,672	25,203,362	11,107,737	3,229,283	5,573,599	2,534,969	2,541,776	215,998	Table 7.3
- Stations	24,146,628	20,247,461	8,923,551	2,594,288	4,477,626	2,036,501	2,041,970	173,525	Table 7.5
- Wires & Related Equipment	106,178,872	50,071,681	22,848,219	6,386,594	10,675,047	4,879,394	4,870,647	215,998	Table 7.11
- Transformers	35,103,294	16,432,013	6,175,369	2,112,410	5,098,870	1,636,722	1,271,021	137,621	Table 7.22
- Meters, (except Meter Reading)	5,982,714	5,442,949	3,793,460	1,215,184	393,840	26,165	14,300	-	Table 7.12
- Streetlights/Floodlights									
Customer Costs	83,935,188	79,436,944	68,709,406	6,474,268	1,166,181	2,238,927	848,161	-	Table 8.28
Low-Income Assistance									
Total	1,896,987,473	1,578,844,752	652,116,941	201,605,660	340,823,157	164,431,082	203,522,933	16,149,196	
Share of Total Marginal Cost	100.000%	83.229%	34.376%	10.628%	17.967%	8.668%	10.729%	0.851%	

	Downtown Network					Source
	Total	Residential	Small	Medium	Large	
Energy	230,295,765	12,890,324	26,645,480	85,330,713	105,429,247	Table 6.7
Production						
Purchased Power						
Transmission - Long Distance						
Conservation						
Retail Service	87,846,957	9,158,638	11,155,014	32,282,368	35,250,937	
Total Distribution	83,348,713	5,889,232	10,513,812	32,101,593	34,844,075	
- Transmission - In Service Area	4,131,309	263,561	483,124	1,465,048	1,919,576	Table 7.3
- Stations	3,899,167	248,751	455,977	1,382,726	1,811,713	Table 7.5
- Wires & Related Equipment	56,107,191	3,626,626	6,553,648	19,816,825	26,110,092	Table 7.11
- Transformers	18,671,280	1,406,024	2,893,592	9,382,400	4,989,265	Table 7.22
- Meters, (except Meter Reading)	539,765	344,270	127,470	54,595	13,429	Table 7.12
- Streetlights/Floodlights						
Customer Costs	4,498,244	3,269,405	641,202	180,774	406,862	Table 8.28
Low-Income Assistance						
Total	318,142,722	22,048,962	37,800,494	117,613,081	140,680,184	
Share of Total Marginal Cost	16.771%	1.162%	1.993%	6.200%	7.416%	

Table 9.3
Summary of Marginal Cost Shares by Functional Category, 2007 + 2008

	Total Nonnetwork (EXcludes Network Residential & Small)							Source
	Total	Residential	Small	Medium	Large	High Demand	Lights	
Energy								
Production	85.716%	32.907%	11.139%	19.440%	9.370%	11.904%	0.956%	Table 6.7
Purchased Power	85.716%	32.907%	11.139%	19.440%	9.370%	11.904%	0.956%	Table 6.7
Transmission - Long Distance	85.716%	32.907%	11.139%	19.440%	9.370%	11.904%	0.956%	Table 6.7
Conservation	85.716%	32.907%	11.139%	19.440%	9.370%	11.904%	0.956%	Table 6.7
Retail Service								
Total Distribution								
- Transmission - In Service Area	85.917%	37.866%	11.008%	19.000%	8.642%	8.665%	0.736%	Table 7.3
- Stations	83.852%	36.956%	10.744%	18.543%	8.434%	8.457%	0.719%	Table 7.5
- Wires & Related Equipment	100.000%	45.631%	12.755%	21.320%	9.745%	9.727%	0.431%	Table 7.11
- Transformers	100.000%	37.581%	12.855%	31.030%	9.961%	7.735%	0.838%	Table 7.22
- Meters, (except Meter Reading)	90.978%	63.407%	20.312%	6.583%	0.437%	0.239%	0.000%	Table 7.12
- Streetlights/Floodlights							100.000%	Sect. 7.1
Customer Costs	94.641%	81.860%	7.713%	1.389%	2.667%	1.010%	0.000%	Table 8.28
Low-Income Assistance	83.229%	34.376%	10.628%	17.967%	8.668%	10.729%	0.851%	Table 9.2
Total								

	Downtown Network					Source
	Total	Residential	Small	Medium	Large	
Energy						
Production	14.284%	0.799%	1.653%	5.292%	6.539%	Table 6.7
Purchased Power	14.284%	0.799%	1.653%	5.292%	6.539%	Table 6.7
Transmission - Long Distance	14.284%	0.799%	1.653%	5.292%	6.539%	Table 6.7
Conservation	14.284%	0.799%	1.653%	5.292%	6.539%	Table 6.7
Retail Service						
Total Distribution						
- Transmission - In Service Area	14.083%	0.898%	1.647%	4.994%	6.544%	Table 7.3
- Stations	16.148%	1.030%	1.888%	5.726%	7.503%	Table 7.5
- Wires & Related Equipment	100.000%	6.464%	11.681%	35.320%	46.536%	Table 7.11
- Transformers	100.000%	7.530%	15.498%	50.250%	26.722%	Table 7.22
- Meters, (except Meter Reading)	9.022%	5.754%	2.131%	0.913%	0.224%	Table 7.12
- Streetlights/Floodlights						Sect. 7.1
Customer Costs	5.359%	3.895%	0.764%	0.215%	0.485%	Table 8.28
Low-Income Assistance	16.771%	1.162%	1.993%	6.200%	7.416%	Table 9.2
Total						

9.3 Initial Allocation of Functional Revenue Requirements

Table 9.4 presents the initial allocation of the functionalized revenue requirements. The marginal cost shares for nonnetwork and network classes are multiplied by the total revenue requirements for each of the functionalized revenue requirement components except for the two categories mentioned above, Wires and Related Equipment and Transformers. The total network revenue requirement for those two categories are multiplied by 85 percent, and those results are then allocated to network customer classes by using the network shares. The remainders of the total revenue requirements for those two categories are then allocated to the nonnetwork customers by the nonnetwork shares by class. Specifically, the total revenue requirements (or total by nonnetwork and network adjusted as just mentioned) from Table 9.1 are multiplied by appropriate shares from Table 9.3. The bottom row in each section shows for each class the share of the total service territory's revenue requirements allocated by marginal cost shares. These shares eventually are used to allocate net wholesale revenues among the classes.

Table 9.5 presents the allocation of the functionalized revenue requirements among the classes in Seattle, Tukwila and the Other Suburbs derived from the total nonnetwork revenue requirements presented in Table 9.4. Those nonnetwork revenue requirements are multiplied by each class's share of total nonnetwork load for that class based on the sum of loads for 2007 and 2008. These shares are from Table 5.5 in Chapter 5. Note, at this stage, Seattle residential customers exclude the network residential customers. Also note that the total revenue requirements for each area equals the sum over all classes in the area rather than the product of share of load for the area and total nonnetwork revenue requirements.[26] The bottom row in each section shows each class's share of the total service territory's revenue requirements that are allocated by marginal cost shares.

Table 9.6 presents the allocated revenue requirements by function by area and class on a dollar per MWH basis. Note that the dollars per MWH for any given functionalized revenue requirement are the same for all nonnetwork customers in the same class, but differ from the corresponding results for the same class in the network area. Also note that the dollars per MWH for Energy are very similar among all classes, reflecting the fact that though there is some differences in load profiles and losses among the classes, these differences are, ultimately, rather small in the over-all scheme of things. Though there are only small differences in Energy results, note that the Energy results are slightly lower for network customers than their nonnetwork counterparts. This reflects, primarily, that network losses are smaller than losses through the nonnetwork distribution system. The most striking results from Table 9.6 are the significantly higher distribution-related revenue requirements. These results reflect the oft-stated proposition that distribution costs for network customers are significantly higher than for their nonnetwork counterparts.

[26] Total revenue requirement for an area, such as Tukwila, is a weighted sum over all the classes in the area. Each area has a different composition of load among the classes. The total load for an area does not reflect the different class composition of that load, hence multipling the share of total nonnetwork load by area by the total revenue requirement for a functionalized revenue requirement will not provide an accurate assessment of the total revenue requirement for any given functional category.

Table 9.4
Initial Allocation of Functionalized Revenue Requirements, 2007 + 2008

	Total Service Territory						
	Total	Residential	Small	Medium	Large	High Demand	Lights
Energy	**$ 962,241,599**	**324,336,512**	**123,085,718**	**237,989,447**	**153,086,520**	**114,548,903**	**9,194,499**
Production	$ 154,094,483	51,939,624	19,711,089	38,111,905	24,515,453	18,343,994	1,472,418
Purchased Power	$ 665,548,308	224,332,036	85,134,016	164,608,840	105,884,504	79,229,404	6,359,508
Transmission - Long Distance	$ 35,697,234	12,032,234	4,566,233	8,828,931	5,679,203	4,249,535	341,097
Conservation	$ 106,901,573	36,032,617	13,674,380	26,439,770	17,007,361	12,725,970	1,021,476
Retail Service	**$ 476,264,787**	**229,958,670**	**54,878,577**	**85,652,235**	**59,201,025**	**24,736,611**	**21,837,670**
Total Distribution	**$ 335,489,615**	**118,374,362**	**42,190,699**	**79,287,625**	**52,410,367**	**21,545,680**	**21,680,882**
- Transmission - In Service Area	$ 19,525,639	7,568,923	2,471,039	4,685,039	2,965,018	1,691,848	143,772
- Stations	$ 65,023,271	24,699,643	8,213,909	15,781,054	10,362,668	5,498,722	467,276
- Wires & Related Equipment	$ 172,220,352	61,550,269	21,499,269	42,805,829	32,784,762	12,521,606	1,058,618
- Transformers	$ 37,491,557	9,747,678	5,201,475	14,410,871	6,156,225	1,782,326	192,983
- Meters, (except Meter Reading)	$ 21,410,562	14,807,850	4,805,007	1,604,832	141,696	51,178	-
- Streetlights/Floodlights	$ 19,818,233	-	-	-	-	-	19,818,233
Customer Costs	***$ 122,578,426***	**105,117,409**	**10,391,388**	**1,967,086**	**3,863,895**	**1,238,649**	**-**
Low-Income Assistance	**$ 18,196,747**	**6,466,899**	**2,296,490**	**4,397,524**	**2,926,763**	**1,952,282**	**156,788**
Total	**$ 1,438,506,386**	**554,295,181**	**177,964,295**	**323,641,681**	**212,287,545**	**139,285,514**	**31,032,169**
Percent of Total Service Territory	**100.000%**	**38.533%**	**12.371%**	**22.498%**	**14.757%**	**9.683%**	**2.157%**

	Total Nonnetwork (EXcludes Network Residential & Small that are billed at nonnetwork rates)						
	Total	Residential	Small	Medium	Large	High Demand	Lights
Energy	**824,798,613**	**316,643,428**	**107,183,409**	**187,063,161**	**90,165,213**	**114,548,903**	**9,194,499**
Production	132,084,204	50,707,645	17,164,475	29,956,511	14,439,162	18,343,994	1,472,418
Purchased Power	570,483,881	219,011,003	74,134,954	129,384,939	62,364,073	79,229,404	6,359,508
Transmission - Long Distance	30,598,375	11,746,836	3,976,290	6,939,668	3,344,949	4,249,535	341,097
Conservation	91,632,153	35,177,943	11,907,690	20,782,043	10,017,030	12,725,970	1,021,476
Retail Service	**393,518,532**	**218,995,744**	**44,254,226**	**56,743,087**	**26,951,194**	**24,736,611**	**21,837,670**
Total Distribution	**262,364,334**	**112,397,559**	**32,865,355**	**51,770,676**	**22,104,183**	**21,545,680**	**21,680,882**
- Transmission - In Service Area	16,775,772	7,393,492	2,149,464	3,709,879	1,687,317	1,691,848	143,772
- Stations	54,523,396	24,029,792	6,986,031	12,057,579	5,483,995	5,498,722	467,276
- Wires & Related Equipment	128,725,793	58,738,891	16,418,850	27,443,733	12,544,095	12,521,606	1,058,618
- Transformers	23,042,257	8,659,586	2,962,186	7,150,035	2,295,140	1,782,326	192,983
- Meters, (except Meter Reading)	19,478,883	13,575,797	4,348,824	1,409,449	93,636	51,178	-
- Streetlights/Floodlights	19,818,233	-	-	-	-	-	19,818,233
Customer Costs	**116,009,218**	**100,342,789**	**9,454,981**	**1,703,084**	**3,269,716**	**1,238,649**	**0**
Low-Income Assistance	**15,144,980**	**6,255,395**	**1,933,891**	**3,269,327**	**1,577,296**	**1,952,282**	**156,788**
Total	**1,218,317,146**	**535,639,172**	**151,437,636**	**243,806,247**	**117,116,408**	**139,285,514**	**31,032,169**
Percent of Total Service Territory	**84.693%**	**37.236%**	**10.527%**	**16.949%**	**8.142%**	**9.683%**	**2.157%**

	Downtown Network				
	Total	Residential	Small	Medium	Large
Energy	**137,442,986**	**7,693,084**	**15,902,309**	**50,926,286**	**62,921,307**
Production	22,010,279	1,231,979	2,546,614	8,155,394	10,076,291
Purchased Power	95,064,427	5,321,033	10,999,062	35,223,902	43,520,431
Transmission - Long Distance	5,098,859	285,398	589,944	1,889,263	2,334,254
Conservation	15,269,420	854,674	1,766,689	5,657,727	6,990,330
Retail Service	**82,746,255**	**10,962,926**	**10,624,351**	**28,909,148**	**32,249,830**
Total Distribution	**73,125,281**	**5,976,803**	**9,325,344**	**27,516,949**	**30,306,184**
- Transmission - In Service Area	2,749,867	175,431	321,575	975,160	1,277,701
- Stations	10,499,876	669,850	1,227,878	3,723,474	4,878,673
- Wires & Related Equipment	43,494,559	2,811,377	5,080,419	15,362,096	20,240,667
- Transformers	14,449,300	1,088,092	2,239,288	7,260,836	3,861,084
- Meters, (except Meter Reading)	1,931,679	1,232,053	456,183	195,383	48,060
- Streetlights/Floodlights	-	-	-	-	-
Customer Costs	**6,569,208**	**4,774,619**	**936,407**	**264,002**	**594,179**
Low-Income Assistance	**3,051,766**	**211,503**	**362,599**	**1,128,197**	**1,349,467**
Total	**220,189,240**	**18,656,010**	**26,526,660**	**79,835,434**	**95,171,137**
Percent of Total Service Territory	**15.307%**	**1.297%**	**1.844%**	**5.550%**	**6.616%**

Table 9.5
Initial Allocation of 2007-08 Nonnetwork Revenue Requirements among Seattle, Tukwila and Other Suburbs

	Seattle Nonnetwork						
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	**671,451,074**	**244,119,217**	**89,471,331**	**157,811,517**	**76,665,812**	**94,188,699**	**9,194,499**
Production	107,526,952	39,093,534	14,328,042	25,272,119	12,277,352	15,083,487	1,472,418
Purchased Power	464,418,839	168,848,584	61,884,139	109,152,617	53,027,017	65,146,975	6,359,508
Transmission - Long Distance	24,909,489	9,056,334	3,319,207	5,854,491	2,844,148	3,494,212	341,097
Conservation	74,595,794	27,120,765	9,939,942	17,532,291	8,517,295	10,464,025	1,021,476
Retail Service	**318,741,659**	**168,836,820**	**36,941,207**	**47,869,995**	**22,916,102**	**20,339,864**	**21,837,670**
Total Distribution	**215,955,192**	**86,653,951**	**27,434,349**	**43,675,135**	**18,794,777**	**17,716,097**	**21,680,882**
- Transmission - In Service Area	13,593,701	5,700,082	1,794,264	3,129,754	1,434,694	1,391,135	143,772
- Stations	44,181,261	18,525,993	5,831,588	10,172,099	4,662,939	4,521,366	467,276
- Wires & Related Equipment	104,163,816	45,285,298	13,705,632	23,152,272	10,666,011	10,295,985	1,058,618
- Transformers	18,790,865	6,676,189	2,472,684	6,031,962	1,951,515	1,465,531	192,983
- Meters, (except Meter Reading)	15,407,315	10,466,388	3,630,180	1,189,049	79,617	42,081	-
- Streetlights/Floodlights	19,818,233	-	-	-	-	-	19,818,233
Customer Costs	**90,488,191**	**77,360,213**	**7,892,543**	**1,436,767**	**2,780,179**	**1,018,488**	**-**
Low-Income Assistance	**12,298,276**	**4,822,656**	**1,614,315**	**2,758,092**	**1,341,146**	**1,605,279**	**156,788**
Total	**990,192,733**	**412,956,037**	**126,412,538**	**205,681,512**	**99,581,913**	**114,528,563**	**31,032,169**
Percent of Total Service Territory	**68.835%**	**28.707%**	**8.788%**	**14.298%**	**6.923%**	**7.962%**	**2.157%**

	Tukwila					
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Energy	**49,879,757**	**5,895,997**	**3,238,823**	**9,206,811**	**11,177,921**	**20,360,204**
Production	7,987,802	944,192	518,669	1,474,389	1,790,045	3,260,507
Purchased Power	34,500,055	4,078,052	2,240,179	6,368,024	7,731,371	14,082,429
Transmission - Long Distance	1,850,439	218,730	120,154	341,554	414,678	755,323
Conservation	5,541,461	655,024	359,822	1,022,843	1,241,827	2,261,945
Retail Service	**15,945,713**	**4,077,768**	**1,337,256**	**2,792,762**	**3,341,181**	**4,396,746**
Total Distribution	**12,203,892**	**2,092,877**	**993,111**	**2,548,031**	**2,740,290**	**3,829,582**
- Transmission - In Service Area	895,105	137,669	64,952	182,592	209,179	300,713
- Stations	2,909,205	447,442	211,101	593,446	679,859	977,356
- Wires & Related Equipment	6,721,322	1,093,736	496,138	1,350,716	1,555,111	2,225,621
- Transformers	1,203,989	161,244	89,510	351,908	284,532	316,795
- Meters, (except Meter Reading)	474,271	252,785	131,411	69,370	11,608	9,096
- Streetlights/Floodlights	-	-	-	-	-	-
Customer Costs	**2,863,454**	**1,868,413**	**285,707**	**83,822**	**405,352**	**220,160**
Low-Income Assistance	**878,367**	**116,477**	**58,438**	**160,909**	**195,540**	**347,003**
Total	**65,825,469**	**9,973,765**	**4,576,079**	**11,999,573**	**14,519,103**	**24,756,950**
Percent of Total Service Territory	**4.576%**	**0.693%**	**0.318%**	**0.834%**	**1.009%**	**1.721%**

	Other Suburbs				
	Total	**Residential**	**Small**	**Medium**	**Large**
Energy	**103,467,782**	**66,628,214**	**14,473,255**	**20,044,833**	**2,321,480**
Production	16,569,450	10,669,919	2,317,764	3,210,003	371,765
Purchased Power	71,564,987	46,084,367	10,010,636	13,864,298	1,605,685
Transmission - Long Distance	3,838,447	2,471,773	536,929	743,623	86,122
Conservation	11,494,898	7,402,154	1,607,926	2,226,909	257,908
Retail Service	**58,831,161**	**46,081,156**	**5,975,764**	**6,080,330**	**693,911**
Total Distribution	**34,205,250**	**23,650,731**	**4,437,894**	**5,547,509**	**569,116**
- Transmission - In Service Area	2,286,966	1,555,741	290,248	397,534	43,443
- Stations	7,432,930	5,056,357	943,342	1,292,035	141,196
- Wires & Related Equipment	17,840,654	12,359,857	2,217,080	2,940,745	322,972
- Transformers	3,047,403	1,822,153	399,992	766,165	59,093
- Meters, (except Meter Reading)	3,597,298	2,856,624	587,233	151,030	2,411
- Streetlights/Floodlights	-	-	-	-	-
Customer Costs	**22,657,573**	**21,114,163**	**1,276,731**	**182,495**	**84,185**
Low-Income Assistance	**1,968,337**	**1,316,262**	**261,138**	**350,326**	**40,611**
Total	**162,298,943**	**112,709,370**	**20,449,019**	**26,125,162**	**3,015,392**
Percent of Total Service Territory	**11.282%**	**7.835%**	**1.422%**	**1.816%**	**0.210%**

Table 9.6
Initial Allocation of 2007-08 Revenue Requirements, $/MWH

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	Seattle Nonnetwork						
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	**50.191**	**50.591**	**50.636**	**50.139**	**49.795**	**49.346**	**48.435**
Production	8.038	8.102	8.109	8.029	7.974	7.902	7.757
Purchased Power	34.715	34.992	35.023	34.679	34.441	34.131	33.501
Transmission - Long Distance	1.862	1.877	1.878	1.860	1.847	1.831	1.797
Conservation	5.576	5.620	5.625	5.570	5.532	5.482	5.381
Retail Service	**23.826**	**34.989**	**20.907**	**15.209**	**14.884**	**10.656**	**115.038**
Total Distribution	**16.143**	**17.958**	**15.526**	**13.876**	**12.207**	**9.282**	**114.212**
- Transmission - In Service Area	1.016	1.181	1.015	0.994	0.932	0.729	0.757
- Stations	3.303	3.839	3.300	3.232	3.029	2.369	2.462
- Wires & Related Equipment	7.786	9.385	7.757	7.356	6.928	5.394	5.577
- Transformers	1.405	1.384	1.399	1.916	1.268	0.768	1.017
- Meters, (except Meter Reading)	1.152	2.169	2.054	0.378	0.052	0.022	-
- Streetlights/Floodlights	1.481	-	-	-	-	-	104.400
Customer Costs	**6.764**	**16.032**	**4.467**	**0.456**	**1.806**	**0.534**	**-**
Low-Income Assistance	**0.919**	**0.999**	**0.914**	**0.876**	**0.871**	**0.841**	**0.826**
Total	**74.016**	**85.580**	**71.543**	**65.348**	**64.679**	**60.002**	**163.473**

	Tukwila					
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Energy	**49.819**	**50.591**	**50.636**	**50.139**	**49.795**	**49.346**
Production	7.978	8.102	8.109	8.029	7.974	7.902
Purchased Power	34.458	34.992	35.023	34.679	34.441	34.131
Transmission - Long Distance	1.848	1.877	1.878	1.860	1.847	1.831
Conservation	5.535	5.620	5.625	5.570	5.532	5.482
Retail Service	**15.926**	**34.989**	**20.907**	**15.209**	**14.884**	**10.656**
Total Distribution	**12.189**	**17.958**	**15.526**	**13.876**	**12.207**	**9.282**
- Transmission - In Service Area	0.894	1.181	1.015	0.994	0.932	0.729
- Stations	2.906	3.839	3.300	3.232	3.029	2.369
- Wires & Related Equipment	6.713	9.385	7.757	7.356	6.928	5.394
- Transformers	1.203	1.384	1.399	1.916	1.268	0.768
- Meters, (except Meter Reading)	0.474	2.169	2.054	0.378	0.052	0.022
- Streetlights/Floodlights	-	-	-	-	-	-
Customer Costs	**2.860**	**16.032**	**4.467**	**0.456**	**1.806**	**0.534**
Low-Income Assistance	**0.877**	**0.999**	**0.914**	**0.876**	**0.871**	**0.841**
Total	**65.746**	**85.580**	**71.543**	**65.348**	**64.679**	**60.002**

	Other Suburbs				
	Total	**Residential**	**Small**	**Medium**	**Large**
Energy	**50.491**	**50.591**	**50.636**	**50.139**	**49.795**
Production	8.086	8.102	8.109	8.029	7.974
Purchased Power	34.923	34.992	35.023	34.679	34.441
Transmission - Long Distance	1.873	1.877	1.878	1.860	1.847
Conservation	5.609	5.620	5.625	5.570	5.532
Retail Service	**28.709**	**34.989**	**20.907**	**15.209**	**14.884**
Total Distribution	**16.692**	**17.958**	**15.526**	**13.876**	**12.207**
- Transmission - In Service Area	1.116	1.181	1.015	0.994	0.932
- Stations	3.627	3.839	3.300	3.232	3.029
- Wires & Related Equipment	8.706	9.385	7.757	7.356	6.928
- Transformers	1.487	1.384	1.399	1.916	1.268
- Meters, (except Meter Reading)	1.755	2.169	2.054	0.378	0.052
- Streetlights/Floodlights	-	-	-	-	-
Customer Costs	**11.057**	**16.032**	**4.467**	**0.456**	**1.806**
Low-Income Assistance	**0.961**	**0.999**	**0.914**	**0.876**	**0.871**
Total	**79.199**	**85.580**	**71.543**	**65.348**	**64.679**

	Downtown Network				
	Total	**Residential**	**Small**	**Medium**	**Large**
Energy	**50.068**	**50.343**	**50.565**	**49.941**	**50.014**
Production	8.018	8.062	8.098	7.998	8.009
Purchased Power	34.631	34.821	34.974	34.542	34.593
Transmission - Long Distance	1.857	1.868	1.876	1.853	1.855
Conservation	5.562	5.593	5.618	5.548	5.556
Retail Service	**30.143**	**71.741**	**33.783**	**28.350**	**25.634**
Total Distribution	**26.638**	**39.112**	**29.652**	**26.985**	**24.089**
- Transmission - In Service Area	1.002	1.148	1.023	0.956	1.016
- Stations	3.825	4.383	3.904	3.651	3.878
- Wires & Related Equipment	15.844	18.398	16.154	15.065	16.089
- Transformers	5.264	7.120	7.120	7.120	3.069
- Meters, (except Meter Reading)	0.704	8.062	1.451	0.192	0.038
- Streetlights/Floodlights	-	-	-	-	-
Customer Costs	**2.393**	**31.245**	**2.978**	**0.259**	**0.472**
Low-Income Assistance	**1.112**	**1.384**	**1.153**	**1.106**	**1.073**
Total	**80.212**	**122.084**	**84.348**	**78.291**	**75.649**

Chapter 10

Final Adjustments to Revenue Requirements: Franchise Contracts; Consolidation of Network Residential and Small with Seattle Nonnetwork; Wholesale Net Revenue Offsets

10.1 Base Rates –Rates without a Rate Change

It is useful to compare the new rates ultimately to be developed for each class with current rates. Such a comparison indicates for each class as a group whether their total bills as a group will increase or decrease. **Table 10.1** presents the annual average rate for the customer classes based on current rates (effective November 2005) but consumption as projected for 2007 and 2008. Average rates for all the Totals, and for the groups at the Service Territory level are weighted averages of rates of their various rate categories.

Table 10.1
Base Rates – Rates without a Rate Change, $/MWH

	Service Territory						
average	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
current rates	61.389	67.235	58.808	60.675	57.472	53.533	75.264
	Total Nonnetwork						
average	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
current rates	61.252	67.235	58.808	59.386	55.698	53.533	75.264
	Seattle Nonnetwork						
average	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
current rates	60.578	66.380	58.600	59.094	55.381	52.784	75.264
	Tukwila						
average	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	
current rates	60.021	70.818	61.600	62.175	57.757	56.999	
	Other Suburbs						
average	**Total**	**Residential**	**Small**	**Medium**	**Large**		
current rates	66.476	70.150	59.700	60.410	56.247		
	Network						
average	**Total**			**Medium**	**Large**		
current rates	62.210			65.392	60.026		

10.2 Adjustments Not Made – Gradualism and Network Costs

This section discusses two kinds of adjustments, gradualism and percent of network incremental network cost recovered, made in previous rate cases that are NOT made in this rate case. Since they are not made here, this rate case differs from the last rate case and it is useful and in some ways important to understand the implications of these adjustments no longer made.

Gradualism is a policy tool that has been used for the past twenty years. It is a tool used after revenue requirements have been allocated by marginal cost shares. The gradualism tool has been used when any class had a rate change, particularly an increase, that was significantly higher than the system average rate increase. Revenue requirements were reduced for that class and the reduction was distributed among other classes. The last rate case also had a rate-change floor as a part of the gradualism process in order to mitigate to some extent disparity in rate changes among customer classes. This tool has been used to make easier the transition to rates based on cost of service and to foster what appeared to be more equitable allocations of necessary rate changes. Never-the-less, it has been a long-standing goal of the rate-making process to eliminate the use of the gradualism tool. It distorts rates from what cost-of-service indicates and gives incorrect price signals to the various classes about the true marginal cost of providing electrical service. These incorrect price signals induce classes with rates below the cost of service to tend to use more than the socially optimum amount of electrical service and, conversely, induces classes which have had higher than cost of service rates to use less than what is socially optimal.

One difficulty with use of the gradualism tool, though, is that it is difficult to stop using it. This is particularly true for classes that have benefited from rates that were lowered by prior gradualism adjustments. These lowered rates increase the percentage change associated with any future rate. **Table 10.2** illustrates the rate changes from the last (1999) rate case associated with marginal cost principles compared to the rates set by the gradualism policy put into effect at that time. As indicated previously, the rates implied by the data in Table 10.2 have been amended ten times in the past several years and are embedded in the rates in Table 10.1, but all the amendments were equal changes to all rates. Hence, new residential rates start from what could be considered a 'biased low' base which means that comparisons of new rates with the current residential rate will have an 'upward tilt' because the base rate is 'artificially' low. The same is true for streetlights. Conversely, rate changes for medium and high demand classes, in particular, will have a 'downward tilt' because their bases are 'artificially high.'

Table 10.2
Marginal Cost Rate Changes and Gradualism Adjusted Rate Changes
For rate year 2001, Cap = 6%, Floor=0%, from 1999 Rate Case

	Res.	Small	Medium	Large	High Dmd	StLts
Marg Cost Rt Chg	10.73%	3.13%	-6.52%	0.93%	-5.57%	29.05%
Gradualism Rt Chg	6.00%	3.15%	0.00%	1.93%	0.00%	6.00%
Difference	-4.73%	0.02%	6.52%	1.00%	5.57%	-23.05%

This rate case finally permits cessation of the use of the gradualism tool. It was not clear at the start of the rate-making process that this goal would be achieved. The cost-of-service model used for this rate case, therefore, made provision for the potential continued application of the gradualism tool. Fortunately, it turned out not necessary to invoke the tool. But it is important in analyzing the final results of this rate case, and in particular comparing rate changes among customer classes, to take into account the biased bases current rates present.

Network rates, higher than corresponding nonnetwork rates, were introduced in the last rate case to address the fact that network service is more costly to provide than nonnetwork service. However, as a type of gradualism for network customers, the full cost of network service was not placed into their rates. The last rate case covered two rate periods. In the first rate period, network rates were set to recover the same cost as nonnetwork customers plus 25 percent of the incremental cost of network service over nonnetwork service. In the second rate period, the cost recovery adjustment was set at 50 percent. This second rate adjustment for network customers was included in one of the ten rate changes since the last rate case.

It has been a goal of the rate-making process to set network rates, ultimately, at full cost of network service. However, it was not clear at the start of this rate case what would be a reasonable and appropriate adjustment relative to the incremental network costs. The advent of favorable wholesale net revenue leading to favorable net income allows this rate case to set network rates at full cost of service and still provide some rate reductions for network customers.

Ridding the rate-making process of the crutches used in the past to help individual customer classes should make interpretation of results of future rate cases more straight-forward and, likely, percentage rate change that are more similar over all customer classes.

10.3 Franchise Contracts

Suburban franchise contracts were signed with Shoreline, Lake Forest Park, SeaTac and Burien in the late ‘90s. These contracts require the Department to pay the suburban cities six percent of the energy-related revenue collected from customers in those cities. The contracts permit the Department to increase the energy-portion of rates to customers in those cities by eight percent if the Seattle City Council approves in a regular rate case proceeding. These rate differentials were taken into account in the last rate case analysis and revenue requirements associated with energy were increased to reflect the allowed contract differential. This act increased total revenue that would be collected ($1,426,000 for 2001) and the extra amount was credited to those considered to be the owners of the Department’s assets, viz., Seattle residential customers.

Tukwila has had a franchise agreement with the Department for many years. As of the last rate case, that agreement required rates to customers in Tukwila to be the same as rates to Seattle customers. Tukwila renegotiated their franchise agreement in 2003 to reflect, in general terms, the other franchise agreements described above. However, the Tukwila franchise contract calls for the Department to pay the City of Tukwila amounts on both the power and distribution portions of the revenues collected from customers in Tukwila. By like token, the contract permits the Department to increase the power and distribution portions of rates to Tukwila customers relative to corresponding rates to Seattle nonnetwork customers. Effective in calendar year 2007, if the Seattle City Council approves, the Tukwila power rates can be increased by 8 percent over power rates for corresponding classes in Seattle and the distribution portion of rates can be 6 percent higher. Similar to the other franchise adjustments, incremental revenue from rates to Tukwila customers is credited to Seattle residential customers.

Table 10.3 presents the calculations for these adjustments to rates. The top two rows present the $/MWH by class from Table 9.6. The next set of rows [labeled as 1S(eattle), 1T(ukwila) and 1O(ther)] present the load for 2007-08 from Table 5.4 The "2" rows indicate the revenue associated with Energy and Non-Energy[27] for the three areas. The "3" rows indicate the amount of incremental revenue associated with the maximum permitted by the franchise contracts. The "4" rows indicate the total amount of revenue by energy, and also non-energy for Tukwila, that have been augmented by the increase stipulated in "3". The "5" rows repeat the $/MWH from the top two rows to indicate energy and non-energy costs per MWH for Seattle nonnetwork customers, then presents the new $/MWH for the two suburban areas. The "6" rows show the ratios of the suburban rates to their counterpart Seattle rates. This set of rows is a double-check to confirm that the ratios conform to the permitted contract terms.[28]

As indicated, the "3" rows indicate how much more the suburban areas will pay over-and-beyond what the cost-of-service analysis suggests because of the franchise contract terms. The sum of those amounts is credited to Seattle nonnetwork residential customers in a subsequent step.

It is useful to emphasize that the franchise adjustments to Tukwila and the other suburban customers reflect contract terms with the various suburban cities. These adjustments are not related to differences in marginal costs of service. The adjustments reflect the fact the suburban cities take payments from City Light (thereby increasing the costs City Light must pay) and, if the Seattle City Council approves, charge customers in those areas may be charged higher rates than rates to corresponding Seattle customers. Hence, all these adjustments occur (and must occur) after revenue requirements for energy and all other cost categories have been established by cost-of-service calculations. The extent to which customer rates are distorted away from cost-of-service rates and thereby distort the socially optimal price signal for electrical service is simply another cost to society of the contracts.

[27] The franchise contracts do not define the 'distribution' portion of rates. This term has been interpreted for operational purposes since the inception of the contracts to mean the difference between the total rate and the energy rate, i.e., as the non-energy rate.

[28] The ratios for the total column for each area do not equal the ratios for the indicated classes as the average rate for the total for each area represents a weighted average of all the classes and the weights for the classes differ among all the areas.

Table 10.3
Suburban Franchise Adjustments

	adj %	Total	Residential	Small	Medium	Large	High Demand	Lights
Base Case Nonnetwork Energy, \$/MWH		50.205	50.591	50.636	50.139	49.795	49.346	48.435
Base Case Nonnetwork Non-Energy, \$/MWH		23.953	34.989	20.907	15.209	14.884	10.656	115.038
1S. Seattle Nonnetwork, MWH		13,378,047	4,825,373	1,766,955	3,147,502	1,539,637	1,908,750	189,830
1T. Tukwila, MWH		1,001,216	116,543	63,963	183,627	224,480	412,603	
1O. Other Suburbs, MWH		2,049,243	1,317,004	285,830	399,788	46,621	-	
2TE. Base Energy Revenue, Tukwila		49,879,757	5,895,997	3,238,823	9,206,811	11,177,921	20,360,204	
2TN. Base Non-Energy Revenue, Tukwila		15,945,713	4,077,768	1,337,256	2,792,762	3,341,181	4,396,746	
2OE. Base Energy Revenue, Other Suburbs		103,467,782	66,628,214	14,473,255	20,044,833	2,321,480	-	
3TE. Adjustment 1, Δ Energy Rev. from Tukwila	8%	3,990,381	471,680	259,106	736,545	894,234	1,628,816	
3TN. Adjustment 1, Δ Non–Energy Rev. from Tukwila	6%	956,743	244,666	80,235	167,566	200,471	263,805	
3OE. Adjustment 1, Δ Energy Rev. from Oth.Subs	8%	8,277,423	5,330,257	1,157,860	1,603,587	185,718	-	
4TE. Adjustment 1, Total Energy Rev. from Tukwila		53,870,137	6,367,677	3,497,929	9,943,356	12,072,155	21,989,021	
4TN. Adjustment 1, Total Non-Energy Rev. from Tukwila		16,902,455	4,322,434	1,417,491	2,960,328	3,541,652	4,660,551	
4OE. Adjustment 1, Total Energy Rev. from Oth.Subs		111,745,205	71,958,471	15,631,116	21,648,419	2,507,199	-	
5SE. Base Energy, \$/MWH, Seattle		50.205	50.591	50.636	50.139	49.795	49.346	
5SN. Base Non-Energy, \$/MWH, Seattle		23.953	34.989	20.907	15.209	14.884	10.656	
5TE. Adjusted Energy, \$/MWH, Tukwila	8%	53.805	54.638	54.687	54.150	53.778	53.293	
5TN. Adjusted Non-Energy, \$/MWH, Tukwila	6%	16.882	37.089	22.161	16.121	15.777	11.295	
5OE. Adjusted Energy, \$/MWH, Oth. Subs	8%	54.530	54.638	54.687	54.150	53.778		
6TE. Check, Ratio, Energy, Tukwila/City	8%	1.072	1.080	1.080	1.080	1.080	1.080	
6TN. Check, Ratio, Non-Energy, Tukwila/City	6%	0.705	1.060	1.060	1.060	1.060	1.060	
6ON. Check, Ratio, Energy, Oth.Subs/City	8%	1.086	1.080	1.080	1.080	1.080		

10.4 Allocation of Net Wholesale Revenue

The revenue requirements allocated based on marginal cost shares are offset by net wholesale revenue. **Table 10.4**, in the top two rows in each section, shows those revenue requirements allocated by marginal cost shares and the share of each class relative to the total revenue requirements allocated by marginal cost shares. Data in these top two rows come from Tables 9.4 and 9.5. The third row of each section indicates the share of net wholesale revenue allocated to each class which equals the class share multiplied by the total net wholesale revenue. The last row in each section presents the net, to this stage in the rate-making process, of all revenue requirement allocations.

Table 10.4
Allocation of Net Wholesale Revenue

	Service Territory						
	Total	Residential	Small	Medium	Large	High Demand	Lights
Initial Allocated Rev Reqmnts	1,438,506,386	554,295,181	177,964,295	323,641,681	212,287,545	139,285,514	31,032,169
Share of Allocated Rev Reqmnts	100.000%	38.533%	12.371%	22.498%	14.757%	9.683%	2.157%
Net Wholesale Power Credits	(317,600,622)	(122,380,058)	(39,291,846)	(71,455,226)	(46,869,904)	(30,752,151)	(6,851,437)
Net Revenue Requirements	1,120,905,764	431,915,124	138,672,450	252,186,455	165,417,641	108,533,363	24,180,732

	Total Nonnetwork						
	Total	Residential	Small	Medium	Large	High Demand	Lights
Initial Allocated Rev Reqmnts	1,218,317,146	535,639,172	151,437,636	243,806,247	117,116,408	139,285,514	31,032,169
Share of Allocated Rev Reqmnts	84.693%	37.236%	10.527%	16.949%	8.142%	9.683%	2.157%
Net Wholesale Power Credits	(268,986,142)	(118,261,091)	(33,435,157)	(53,828,761)	(25,857,545)	(30,752,151)	(6,851,437)
Net Revenue Requirements	949,331,003	417,378,081	118,002,478	189,977,487	91,258,863	108,533,363	24,180,732

	Seattle Nonnetwork						
	Total	Residential	Small	Medium	Large	High Demand	Lights
Initial Allocated Rev Reqmnts	990,192,733	412,956,037	126,412,538	205,681,512	99,581,913	114,528,563	31,032,169
Share of Allocated Rev Reqmnts	68.835%	28.707%	8.788%	14.298%	6.923%	7.962%	2.157%
Net Wholesale Power Credits	(218,619,695)	(91,174,496)	(27,909,991)	(45,411,391)	(21,986,192)	(25,286,188)	(6,851,437)
Net Revenue Requirements	771,573,038	321,781,541	98,502,547	160,270,121	77,595,721	89,242,375	24,180,732

	Tukwila					
	Total	Residential	Small	Medium	Large	High Demand
Initial Allocated Rev Reqmnts	65,825,469	9,973,765	4,576,079	11,999,573	14,519,103	24,756,950
Share of Allocated Rev Reqmnts	4.576%	0.693%	0.318%	0.834%	1.009%	1.721%
Net Wholesale Power Credits	(14,533,276)	(2,202,058)	(1,010,330)	(2,649,326)	(3,205,600)	(5,465,963)
Net Revenue Requirements	51,292,194	7,771,707	3,565,749	9,350,247	11,313,503	19,290,987

	Other Suburbs				
	Total	Residential	Small	Medium	Large
Initial Allocated Rev Reqmnts	162,298,943	112,709,370	20,449,019	26,125,162	3,015,392
Share of Allocated Rev Reqmnts	11.282%	7.835%	1.422%	1.816%	0.210%
Net Wholesale Power Credits	(35,833,171)	(24,884,537)	(4,514,836)	(5,768,044)	(665,753)
Net Revenue Requirements	126,465,772	87,824,833	15,934,182	20,357,119	2,349,638

	Network				
	Total	Residential	Small	Medium	Large
Initial Allocated Rev Reqmnts	220,189,240	18,656,010	26,526,660	79,835,434	95,171,137
Share of Allocated Rev Reqmnts	15.307%	1.297%	1.844%	5.550%	6.616%
Net Wholesale Power Credits	(48,614,480)	(4,118,967)	(5,856,688)	(17,626,466)	(21,012,359)
Net Revenue Requirements	171,574,761	14,537,043	20,669,971	62,208,968	74,158,778

10.5 Consolidation of Network Residential and Small Classes with Seattle Residential and Small Classes and Crediting Seattle Residential Class with Suburban Adjustment

The major beneficiaries of network service, it is assumed, are the medium and large customers within the network area. The cost of service and an allocation of revenue requirements was estimated for all classes within the network area (Table 9.4) and adjusted by a proportionate share of net wholesale power credits (Table 10.4). But as one of the final steps in the allocation of revenue requirements, the revenue requirements and loads for the network residential and small customers are consolidated with the revenue requirements and loads for Seattle non-network residential and small customers. Next, the sum of the franchise adjustments from the "3" rows in Table 10.2 are credited to Seattle residential customers. Thus, one set of rates is established for all residential and one set of rates for all small customers within Seattle. **Table 10.5** presents these consolidations.

Table 10.5
Consolidation of Seattle Residential and Small Classes
And Crediting Seattle Residential with Revenue from Franchise Adjustments

	Seattle			Network		
	Residential	**Small**	source	**Residential**	**Small**	source
Net Rev Reqmnt	321,781,541	98,502,547	Table 10.4	14,537,043	20,669,971	Table 10.4

	Seattle + Network		
	Residential	**Small**	source
Net Rev Reqmnt	336,318,584	119,172,518	
Franchise Adjustment	(13,224,546)		Table 10.3
Adjusted Rev. Reqmnt	323,094,038	119,172,518	

10.6 Summary of Final Allocation of Revenue Requirements and Observations

Tables 10.6 – 10.11 present a detailed summary of all pertinent data from the tables in chapters 9 and 10. Note that tables representing consolidations of more detailed classes, such as the Total Nonnetwork and the Total Service Territory tables, show the sums of details from the tables of the detailed classes. Table **10.12** presents a one-page summary of the major data items. The results in these tables represent the final outcome of the cost of service model including the adjustments permitted by the franchise contracts, when accepted by the Seattle City Council, and the consolidation of all residential and small general service customers within the City of Seattle.

It is important, when judging or comparing among customer classes percentage changes from current rates, to include the reckoning of the bias in the starting rate as explained in section 10.2 and partially illustrated in Table 10.2. This caution is especially appropriate in interpreting the relatively low percentage decrease for residential classes compared to the higher percentage declines for medium and high demand classes. Additionally the high percentage change in streetlight rates reflects a combination of the artificially low base rate from the last rate case, given the streetlight revenue requirements, and the recognition, as explained in the *2007-08 RRA*, that those streetlight revenue requirements have had to be significantly increased since the last rate case.

Table 10.6
Detailed Summary of Final Allocation of Revenue Requirements for 2007-08
TOTAL SERVICE TERRITORY

	Total Service Territory						
Total $	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	962,241,599	324,336,512	123,085,718	237,989,447	153,086,520	114,548,903	9,194,499
Production	154,094,483	51,939,624	19,711,089	38,111,905	24,515,453	18,343,994	1,472,418
Purchased Power	665,548,308	224,332,036	85,134,016	164,608,840	105,884,504	79,229,404	6,359,508
Transmission - Long Distance	35,697,234	12,032,234	4,566,233	8,828,931	5,679,203	4,249,535	341,097
Conservation	106,901,573	36,032,617	13,674,380	26,439,770	17,007,361	12,725,970	1,021,476
Retail Service	476,264,787	229,958,670	54,878,577	85,652,235	59,201,025	24,736,611	21,837,670
Total Distribution	335,489,615	118,374,362	42,190,699	79,287,625	52,410,367	21,545,680	21,680,882
- Transmission - In Service Area	19,525,639	7,568,923	2,471,039	4,685,039	2,965,018	1,691,848	143,772
- Stations	65,023,271	24,699,643	8,213,909	15,781,054	10,362,668	5,498,722	467,276
- Wires & Related Equipment	172,220,352	61,550,269	21,499,269	42,805,829	32,784,762	12,521,606	1,058,618
- Transformers	37,491,557	9,747,678	5,201,475	14,410,871	6,156,225	1,782,326	192,983
- Meters, (except Meter Reading)	21,410,562	14,807,850	4,805,007	1,604,832	141,696	51,178	0
- Streetlights/Floodlights	19,818,233	0	0	0	0	0	19,818,233
Customer Costs	122,578,426	105,117,409	10,391,388	1,967,086	3,863,895	1,238,649	0
Low-Income Assistance	18,196,747	6,466,899	2,296,490	4,397,524	2,926,763	1,952,282	156,788
Total	1,438,506,386	554,295,181	177,964,295	323,641,681	212,287,545	139,285,514	31,032,169
Share of Total	100.000%	38.533%	12.371%	22.498%	14.757%	9.683%	2.157%
Franchise Engy Adjustment	12,267,803	5,801,937	1,416,966	2,340,131	1,079,952	1,628,816	0
Franchise Non-Engy Adjustment	956,743	244,666	80,235	167,566	200,471	263,805	0
Seattle Res Adjust for Franch. Adjust.	-13,224,546	-13,224,546	0	0	0	0	0
Sum of Franchise Adjustments	0	-7,177,943	1,497,202	2,507,697	1,280,423	1,892,621	0
Revised Total	1,438,506,386	547,117,239	179,461,497	326,149,378	213,567,968	141,178,135	31,032,169
Net Wholesale Revenue Credit	-317,600,622	-122,380,058	-39,291,846	-71,455,226	-46,869,904	-30,752,151	-6,851,437
Final Revenue Requirement	**1,120,905,764**	**424,737,181**	**140,169,651**	**254,694,152**	**166,698,064**	**110,425,984**	**24,180,732**
Load	19,173,605	6,411,733	2,431,239	4,750,645	3,068,805	2,321,353	189,830
New Average Annual Rate, $/MWH	**58.461**	**66.244**	**57.654**	**53.613**	**54.320**	**47.570**	**127.381**
Current Rate, $/MWH	61.389	67.235	58.808	60.675	57.472	53.533	75.264
Percent Change in Rate	**-4.77%**	**-1.47%**	**-1.96%**	**-11.64%**	**-5.48%**	**-11.14%**	**69.25%**

$/MWH							
Energy	50.186	50.585	50.627	50.096	49.885	49.346	48.435
Production	8.037	8.101	8.107	8.022	7.989	7.902	7.757
Purchased Power	34.712	34.988	35.017	34.650	34.503	34.131	33.501
Transmission - Long Distance	1.862	1.877	1.878	1.858	1.851	1.831	1.797
Conservation	5.575	5.620	5.624	5.566	5.542	5.482	5.381
Retail Service	24.840	35.865	22.572	18.030	19.291	10.656	115.038
Total Distribution	17.497	18.462	17.354	16.690	17.078	9.282	114.212
- Transmission - In Service Area	1.018	1.180	1.016	0.986	0.966	0.729	0.757
- Stations	3.391	3.852	3.378	3.322	3.377	2.369	2.462
- Wires & Related Equipment	8.982	9.600	8.843	9.011	10.683	5.394	5.577
- Transformers	1.955	1.520	2.139	3.033	2.006	0.768	1.017
- Meters, (except Meter Reading)	1.117	2.309	1.976	0.338	0.046	0.022	0.000
- Streetlights/Floodlights	1.034	0.000	0.000	0.000	0.000	0.000	104.400
Customer Costs	6.393	16.395	4.274	0.414	1.259	0.534	0.000
Low-Income Assistance	0.949	1.009	0.945	0.926	0.954	0.841	0.826
Total	75.025	86.450	73.199	68.126	69.176	60.002	163.473
Share of Total	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Franchise Engy Adjustment	0.640	0.905	0.583	0.493	0.352	0.702	0.000
Franchise Non-Engy Adjustment	0.050	0.038	0.033	0.035	0.065	0.114	0.000
Seattle Res Adjust for Franch. Adjust.	-0.690	-2.063	0.000	0.000	0.000	0.000	0.000
Sum of Franchise Adjustments	0.000	-1.120	0.616	0.528	0.417	0.815	0.000
Revised Total	75.025	85.331	73.815	68.654	69.593	60.817	163.473
Net Wholesale Revenue Credit	-16.564	-19.087	-16.161	-15.041	-15.273	-13.248	-36.092
Final Revenue Requirement	**58.461**	**66.244**	**57.654**	**53.613**	**54.320**	**47.570**	**127.381**

Table 10.7
Detailed Summary of Final Allocation of Revenue Requirements for 2007-08
TOTAL NONNETWORK

	Total Nonnetwork (Excluding Network Residential and Small)						
Total $	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	824,798,613	316,643,428	107,183,409	187,063,161	90,165,213	114,548,903	9,194,499
Production	132,084,204	50,707,645	17,164,475	29,956,511	14,439,162	18,343,994	1,472,418
Purchased Power	570,483,881	219,011,003	74,134,954	129,384,939	62,364,073	79,229,404	6,359,508
Transmission - Long Distance	30,598,375	11,746,836	3,976,290	6,939,668	3,344,949	4,249,535	341,097
Conservation	91,632,153	35,177,943	11,907,690	20,782,043	10,017,030	12,725,970	1,021,476
Retail Service	393,518,532	218,995,744	44,254,226	56,743,087	26,951,194	24,736,611	21,837,670
Total Distribution	262,364,334	112,397,559	32,865,355	51,770,676	22,104,183	21,545,680	21,680,882
- Transmission - In Service Area	16,775,772	7,393,492	2,149,464	3,709,879	1,687,317	1,691,848	143,772
- Stations	54,523,396	24,029,792	6,986,031	12,057,579	5,483,995	5,498,722	467,276
- Wires & Related Equipment	128,725,793	58,738,891	16,418,850	27,443,733	12,544,095	12,521,606	1,058,618
- Transformers	23,042,257	8,659,586	2,962,186	7,150,035	2,295,140	1,782,326	192,983
- Meters, (except Meter Reading)	19,478,883	13,575,797	4,348,824	1,409,449	93,636	51,178	0
- Streetlights/Floodlights	19,818,233	0	0	0	0	0	19,818,233
Customer Costs	116,009,218	100,342,789	9,454,981	1,703,084	3,269,716	1,238,649	0
Low-Income Assistance	15,144,980	6,255,395	1,933,891	3,269,327	1,577,296	1,952,282	156,788
Total	1,218,317,146	535,639,172	151,437,636	243,806,247	117,116,408	139,285,514	31,032,169
Share of Total	100.000%	43.965%	12.430%	20.012%	9.613%	11.433%	2.547%
Franchise Engy Adjustment	12,267,803	5,801,937	1,416,966	2,340,131	1,079,952	1,628,816	0
Franchise Non-Engy Adjustment	956,743	244,666	80,235	167,566	200,471	263,805	0
Seattle Res Adjust for Franch. Adjust.	-13,224,546	-13,224,546	0	0	0	0	0
Sum of Franchise Adjustments	0	-7,177,943	1,497,202	2,507,697	1,280,423	1,892,621	0
Revised Total	1,218,317,146	528,461,229	152,934,837	246,313,945	118,396,831	141,178,135	31,032,169
Net Wholesale Revenue Credit	-278,961,797	-122,380,058	-39,291,846	-53,828,761	-25,857,545	-30,752,151	-6,851,437
Final Revenue Requirement	**984,538,017**	**424,737,181**	**140,169,651**	**192,485,184**	**92,539,286**	**110,425,984**	**24,180,732**
Load	16,428,506	6,258,920	2,116,748	3,730,917	1,810,738	2,321,353	189,830
New Average Annual Rate, $/MWH	**59.929**	**67.861**	**66.219**	**51.592**	**51.106**	**47.570**	**127.381**
Current Rate, $/MWH	61.252	67.235	58.808	59.386	55.698	53.533	75.264
Percent Change in Rate	**-2.16%**	**0.93%**	**12.60%**	**-13.12%**	**-8.24%**	**-11.14%**	**69.25%**

$/MWH							
Energy	50.205	50.591	50.636	50.139	49.795	49.346	48.435
Production	8.040	8.102	8.109	8.029	7.974	7.902	7.757
Purchased Power	34.725	34.992	35.023	34.679	34.441	34.131	33.501
Transmission - Long Distance	1.863	1.877	1.878	1.860	1.847	1.831	1.797
Conservation	5.578	5.620	5.625	5.570	5.532	5.482	5.381
Retail Service	23.953	34.989	20.907	15.209	14.884	10.656	115.038
Total Distribution	15.970	17.958	15.526	13.876	12.207	9.282	114.212
- Transmission - In Service Area	1.021	1.181	1.015	0.994	0.932	0.729	0.757
- Stations	3.319	3.839	3.300	3.232	3.029	2.369	2.462
- Wires & Related Equipment	7.836	9.385	7.757	7.356	6.928	5.394	5.577
- Transformers	1.403	1.384	1.399	1.916	1.268	0.768	1.017
- Meters, (except Meter Reading)	1.186	2.169	2.054	0.378	0.052	0.022	0.000
- Streetlights/Floodlights	1.206	0.000	0.000	0.000	0.000	0.000	104.400
Customer Costs	7.061	16.032	4.467	0.456	1.806	0.534	0.000
Low-Income Assistance	0.922	0.999	0.914	0.876	0.871	0.841	0.826
Total	74.159	85.580	71.543	65.348	64.679	60.002	163.473
Share of Total	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Franchise Engy Adjustment	0.747	0.927	0.669	0.627	0.596	0.702	0.000
Franchise Non-Engy Adjustment	0.058	0.039	0.038	0.045	0.111	0.114	0.000
Seattle Res Adjust for Franch. Adjust.	-0.805	-2.113	0.000	0.000	0.000	0.000	0.000
Sum of Franchise Adjustments	0.000	-1.147	0.707	0.672	0.707	0.815	0.000
Revised Total	74.159	84.433	72.250	66.020	65.386	60.817	163.473
Net Wholesale Revenue Credit	-16.980	-19.553	-18.562	-14.428	-14.280	-13.248	-36.092
Final Revenue Requirement	**59.929**	**67.861**	**66.219**	**51.592**	**51.106**	**47.570**	**127.381**

	Total Nonnetwork (Including Network Residential and Small)						
Total $	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Final Revenue Requirement	**984,538,017**	**424,737,181**	**140,169,651**	**192,485,184**	**92,539,286**	**110,425,984**	**24,180,732**
Load	16,895,810	6,411,733	2,431,239	3,730,917	1,810,738	2,321,353	189,830
New Average Annual Rate, $/MWH	**58.271**	**66.244**	**57.654**	**51.592**	**51.106**	**47.570**	**127.381**
Current Rate, $/MWH	61.252	67.235	58.808	59.386	55.698	53.533	75.264
Percent Change in Rate	**-4.87%**	**-1.47%**	**-1.96%**	**-13.12%**	**-8.24%**	**-11.14%**	**69.25%**

Table 10.8
Detailed Summary of Final Allocation of Revenue Requirements for 2007-08
SEATTLE

	Seattle Nonnetwork (Excluding Network Residential and Small)						
Total $	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	671,451,074	244,119,217	89,471,331	157,811,517	76,665,812	94,188,699	9,194,499
Production	107,526,952	39,093,534	14,328,042	25,272,119	12,277,352	15,083,487	1,472,418
Purchased Power	464,418,839	168,848,584	61,884,139	109,152,617	53,027,017	65,146,975	6,359,508
Transmission - Long Distance	24,909,489	9,056,334	3,319,207	5,854,491	2,844,148	3,494,212	341,097
Conservation	74,595,794	27,120,765	9,939,942	17,532,291	8,517,295	10,464,025	1,021,476
Retail Service	318,741,659	168,836,820	36,941,207	47,869,995	22,916,102	20,339,864	21,837,670
Total Distribution	215,955,192	86,653,951	27,434,349	43,675,135	18,794,777	17,716,097	21,680,882
- Transmission - In Service Area	13,593,701	5,700,082	1,794,264	3,129,754	1,434,694	1,391,135	143,772
- Stations	44,181,261	18,525,993	5,831,588	10,172,099	4,662,939	4,521,366	467,276
- Wires & Related Equipment	104,163,816	45,285,298	13,705,632	23,152,272	10,666,011	10,295,985	1,058,618
- Transformers	18,790,865	6,676,189	2,472,684	6,031,962	1,951,515	1,465,531	192,983
- Meters, (except Meter Reading)	15,407,315	10,466,388	3,630,180	1,189,049	79,617	42,081	0
- Streetlights/Floodlights	19,818,233	0	0	0	0	0	19,818,233
Customer Costs	90,488,191	77,360,213	7,892,543	1,436,767	2,780,179	1,018,488	0
Low-Income Assistance	12,298,276	4,822,656	1,614,315	2,758,092	1,341,146	1,605,279	156,788
Total	990,192,733	412,956,037	126,412,538	205,681,512	99,581,913	114,528,563	31,032,169
Share of Total	100.000%	41.705%	12.766%	20.772%	10.057%	11.566%	3.134%
Franchise Engy Adjustment	0	0	0	0	0	0	0
Franchise Non-Engy Adjustment	0	0	0	0	0	0	0
Seattle Res Adjust for Franch. Adjust.	-13,224,546	-13,224,546	0	0	0	0	0
Sum of Franchise Adjustments	-13,224,546	-13,224,546	0	0	0	0	0
Revised Total	976,968,188	399,731,491	126,412,538	205,681,512	99,581,913	114,528,563	31,032,169
Net Wholesale Revenue Credit	-228,595,351	-95,293,463	-33,766,680	-45,411,391	-21,986,192	-25,286,188	-6,851,437
Final Revenue Requirement	**793,555,506**	**323,094,038**	**119,172,518**	**160,270,121**	**77,595,721**	**89,242,375**	**24,180,732**
Load	13,378,047	4,825,373	1,766,955	3,147,502	1,539,637	1,908,750	189,830
New Average Annual Rate, $/MWH	**59.318**	**66.957**	**67.445**	**50.920**	**50.399**	**46.754**	**127.381**
Current Rate, $/MWH	60.578	66.380	58.600	59.094	55.381	52.784	75.264
Percent Change in Rate	**-2.08%**	**0.87%**	**15.09%**	**-13.83%**	**-9.00%**	**-11.42%**	**69.25%**
$/MWH							
Energy	50.191	50.591	50.636	50.139	49.795	49.346	48.435
Production	8.038	8.102	8.109	8.029	7.974	7.902	7.757
Purchased Power	34.715	34.992	35.023	34.679	34.441	34.131	33.501
Transmission - Long Distance	1.862	1.877	1.878	1.860	1.847	1.831	1.797
Conservation	5.576	5.620	5.625	5.570	5.532	5.482	5.381
Retail Service	23.826	34.989	20.907	15.209	14.884	10.656	115.038
Total Distribution	16.143	17.958	15.526	13.876	12.207	9.282	114.212
- Transmission - In Service Area	1.016	1.181	1.015	0.994	0.932	0.729	0.757
- Stations	3.303	3.839	3.300	3.232	3.029	2.369	2.462
- Wires & Related Equipment	7.786	9.385	7.757	7.356	6.928	5.394	5.577
- Transformers	1.405	1.384	1.399	1.916	1.268	0.768	1.017
- Meters, (except Meter Reading)	1.152	2.169	2.054	0.378	0.052	0.022	0.000
- Streetlights/Floodlights	1.481	0.000	0.000	0.000	0.000	0.000	104.400
Customer Costs	6.764	16.032	4.467	0.456	1.806	0.534	0.000
Low-Income Assistance	0.919	0.999	0.914	0.876	0.871	0.841	0.826
Total	74.016	85.580	71.543	65.348	64.679	60.002	163.473
Share of Total	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Franchise Engy Adjustment	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Franchise Non-Engy Adjustment	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Seattle Res Adjust for Franch. Adjust.	-0.989	-2.741	0.000	0.000	0.000	0.000	0.000
Sum of Franchise Adjustments	-0.989	-2.741	0.000	0.000	0.000	0.000	0.000
Revised Total	73.028	82.840	71.543	65.348	64.679	60.002	163.473
Net Wholesale Revenue Credit	-17.087	-19.748	-19.110	-14.428	-14.280	-13.248	-36.092
Final Revenue Requirement	**59.318**	**66.957**	**67.445**	**50.920**	**50.399**	**46.754**	**127.381**

	Seattle Nonnetwork (Including Network Residential and Small)						
Total $	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Final Revenue Requirement	**793,555,506**	**323,094,038**	**119,172,518**	**160,270,121**	**77,595,721**	**89,242,375**	**24,180,732**
Load	13,845,351	4,978,186	2,081,446	3,147,502	1,539,637	1,908,750	189,830
New Average Annual Rate, $/MWH	**57.316**	**64.902**	**57.255**	**50.920**	**50.399**	**46.754**	**127.381**
Current Rate, $/MWH	60.578	66.380	58.600	59.094	55.381	52.784	75.264
Percent Change in Rate	**-5.39%**	**-2.23%**	**-2.30%**	**-13.83%**	**-9.00%**	**-11.42%**	**69.25%**

Table 10.9
Detailed Summary of Final Allocation of Revenue Requirements for 2007-08
TUKWILA

	Tukwila					
Total $	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Energy	49,879,757	5,895,997	3,238,823	9,206,811	11,177,921	20,360,204
Production	7,987,802	944,192	518,669	1,474,389	1,790,045	3,260,507
Purchased Power	34,500,055	4,078,052	2,240,179	6,368,024	7,731,371	14,082,429
Transmission - Long Distance	1,850,439	218,730	120,154	341,554	414,678	755,323
Conservation	5,541,461	655,024	359,822	1,022,843	1,241,827	2,261,945
Retail Service	15,945,713	4,077,768	1,337,256	2,792,762	3,341,181	4,396,746
Total Distribution	12,203,892	2,092,877	993,111	2,548,031	2,740,290	3,829,582
- Transmission - In Service Area	895,105	137,669	64,952	182,592	209,179	300,713
- Stations	2,909,205	447,442	211,101	593,446	679,859	977,356
- Wires & Related Equipment	6,721,322	1,093,736	496,138	1,350,716	1,555,111	2,225,621
- Transformers	1,203,989	161,244	89,510	351,908	284,532	316,795
- Meters, (except Meter Reading)	474,271	252,785	131,411	69,370	11,608	9,096
- Streetlights/Floodlights	0	0	0	0	0	0
Customer Costs	2,863,454	1,868,413	285,707	83,822	405,352	220,160
Low-Income Assistance	878,367	116,477	58,438	160,909	195,540	347,003
Total	65,825,469	9,973,765	4,576,079	11,999,573	14,519,103	24,756,950
Share of Total	100.000%	15.152%	6.952%	18.229%	22.057%	37.610%
Franchise Engy Adjustment	3,990,381	471,680	259,106	736,545	894,234	1,628,816
Franchise Non-Engy Adjustment	956,743	244,666	80,235	167,566	200,471	263,805
Seattle Res Adjust for Franch. Adjust.	0	0	0	0	0	0
Sum of Franchise Adjustments	4,947,123	716,346	339,341	904,111	1,094,705	1,892,621
Revised Total	70,772,593	10,690,111	4,915,420	12,903,683	15,613,807	26,649,571
Net Wholesale Revenue Credit	-14,533,276	-2,202,058	-1,010,330	-2,649,326	-3,205,600	-5,465,963
Final Revenue Requirement	**56,239,317**	**8,488,053**	**3,905,090**	**10,254,358**	**12,408,207**	**21,183,608**
Load	1,001,216	116,543	63,963	183,627	224,480	412,603
New Average Annual Rate, $/MWH	**56.171**	**72.832**	**61.052**	**55.843**	**55.275**	**51.341**
Current Rate, $/MWH	60.021	70.818	61.600	62.175	57.757	56.999
Percent Change in Rate	**-6.41%**	**2.84%**	**-0.89%**	**-10.18%**	**-4.30%**	**-9.93%**
$/MWH						
Energy	49.819	50.591	50.636	50.139	49.795	49.346
Production	7.978	8.102	8.109	8.029	7.974	7.902
Purchased Power	34.458	34.992	35.023	34.679	34.441	34.131
Transmission - Long Distance	1.848	1.877	1.878	1.860	1.847	1.831
Conservation	5.535	5.620	5.625	5.570	5.532	5.482
Retail Service	15.926	34.989	20.907	15.209	14.884	10.656
Total Distribution	12.189	17.958	15.526	13.876	12.207	9.282
- Transmission - In Service Area	0.894	1.181	1.015	0.994	0.932	0.729
- Stations	2.906	3.839	3.300	3.232	3.029	2.369
- Wires & Related Equipment	6.713	9.385	7.757	7.356	6.928	5.394
- Transformers	1.203	1.384	1.399	1.916	1.268	0.768
- Meters, (except Meter Reading)	0.474	2.169	2.054	0.378	0.052	0.022
- Streetlights/Floodlights	0.000	0.000	0.000	0.000	0.000	0.000
Customer Costs	2.860	16.032	4.467	0.456	1.806	0.534
Low-Income Assistance	0.877	0.999	0.914	0.876	0.871	0.841
Total	65.746	85.580	71.543	65.348	64.679	60.002
Share of Total	0.000	0.000	0.000	0.000	0.000	0.000
Franchise Engy Adjustment	3.986	4.047	4.051	4.011	3.984	3.948
Franchise Non-Engy Adjustment	0.956	2.099	1.254	0.913	0.893	0.639
Seattle Res Adjust for Franch. Adjust.	0.000	0.000	0.000	0.000	0.000	0.000
Sum of Franchise Adjustments	4.941	6.147	5.305	4.924	4.877	4.587
Revised Total	70.687	91.727	76.848	70.271	69.555	64.589
Net Wholesale Revenue Credit	-14.516	-18.895	-15.796	-14.428	-14.280	-13.248
Final Revenue Requirement	**56.171**	**72.832**	**61.052**	**55.843**	**55.275**	**51.341**

Table 10.10
Detailed Summary of Final Allocation of Revenue Requirements for 2007-08
OTHER SUBURBS

	Other Suburbs				
Total $	**Total**	**Residential**	**Small**	**Medium**	**Large**
Energy	103,467,782	66,628,214	14,473,255	20,044,833	2,321,480
Production	16,569,450	10,669,919	2,317,764	3,210,003	371,765
Purchased Power	71,564,987	46,084,367	10,010,636	13,864,298	1,605,685
Transmission - Long Distance	3,838,447	2,471,773	536,929	743,623	86,122
Conservation	11,494,898	7,402,154	1,607,926	2,226,909	257,908
Retail Service	58,831,161	46,081,156	5,975,764	6,080,330	693,911
Total Distribution	34,205,250	23,650,731	4,437,894	5,547,509	569,116
- Transmission - In Service Area	2,286,966	1,555,741	290,248	397,534	43,443
- Stations	7,432,930	5,056,357	943,342	1,292,035	141,196
- Wires & Related Equipment	17,840,654	12,359,857	2,217,080	2,940,745	322,972
- Transformers	3,047,403	1,822,153	399,992	766,165	59,093
- Meters, (except Meter Reading)	3,597,298	2,856,624	587,233	151,030	2,411
- Streetlights/Floodlights	0	0	0	0	0
Customer Costs	22,657,573	21,114,163	1,276,731	182,495	84,185
Low-Income Assistance	1,968,337	1,316,262	261,138	350,326	40,611
Total	162,298,943	112,709,370	20,449,019	26,125,162	3,015,392
Share of Total	100.000%	69.446%	12.600%	16.097%	1.858%
Franchise Engy Adjustment	8,277,423	5,330,257	1,157,860	1,603,587	185,718
Franchise Non-Engy Adjustment	0	0	0	0	0
Seattle Res Adjust for Franch. Adjust.	0	0	0	0	0
Sum of Franchise Adjustments	8,277,423	5,330,257	1,157,860	1,603,587	185,718
Revised Total	170,576,365	118,039,627	21,606,879	27,728,749	3,201,110
Net Wholesale Revenue Credit	-35,833,171	-24,884,537	-4,514,836	-5,768,044	-665,753
Final Revenue Requirement	**134,743,194**	**93,155,090**	**17,092,043**	**21,960,705**	**2,535,357**
Load	2,049,243	1,317,004	285,830	399,788	46,621
New Average Annual Rate, $/MWH	**65.753**	**70.733**	**59.798**	**54.931**	**54.382**
Current Rate, $/MWH	66.476	70.150	59.700	60.410	56.247
Percent Change in Rate	**-1.09%**	**0.83%**	**0.16%**	**-9.07%**	**-3.32%**
$/MWH					
Energy	50.491	50.591	50.636	50.139	49.795
Production	8.086	8.102	8.109	8.029	7.974
Purchased Power	34.923	34.992	35.023	34.679	34.441
Transmission - Long Distance	1.873	1.877	1.878	1.860	1.847
Conservation	5.609	5.620	5.625	5.570	5.532
Retail Service	28.709	34.989	20.907	15.209	14.884
Total Distribution	16.692	17.958	15.526	13.876	12.207
- Transmission - In Service Area	1.116	1.181	1.015	0.994	0.932
- Stations	3.627	3.839	3.300	3.232	3.029
- Wires & Related Equipment	8.706	9.385	7.757	7.356	6.928
- Transformers	1.487	1.384	1.399	1.916	1.268
- Meters, (except Meter Reading)	1.755	2.169	2.054	0.378	0.052
- Streetlights/Floodlights	0.000	0.000	0.000	0.000	0.000
Customer Costs	11.057	16.032	4.467	0.456	1.806
Low-Income Assistance	0.961	0.999	0.914	0.876	0.871
Total	79.199	85.580	71.543	65.348	64.679
Share of Total	0.000	0.000	0.000	0.000	0.000
Franchise Engy Adjustment	4.039	4.047	4.051	4.011	3.984
Franchise Non-Engy Adjustment	0.000	0.000	0.000	0.000	0.000
Seattle Res Adjust for Franch. Adjust.	0.000	0.000	0.000	0.000	0.000
Sum of Franchise Adjustments	4.039	4.047	4.051	4.011	3.984
Revised Total	83.239	89.627	75.593	69.359	68.662
Net Wholesale Revenue Credit	-17.486	-18.895	-15.796	-14.428	-14.280
Final Revenue Requirement	**65.753**	**70.733**	**59.798**	**54.931**	**54.382**

Table 10.11
Detailed Summary of Final Allocation of Revenue Requirements for 2007-08
NETWORK

	Network				
Total $	**Total**	**Residential**	**Small**	**Medium**	**Large**
Energy	137,442,986	7,693,084	15,902,309	50,926,286	62,921,307
Production	22,010,279	1,231,979	2,546,614	8,155,394	10,076,291
Purchased Power	95,064,427	5,321,033	10,999,062	35,223,902	43,520,431
Transmission - Long Distance	5,098,859	285,398	589,944	1,889,263	2,334,254
Conservation	15,269,420	854,674	1,766,689	5,657,727	6,990,330
Retail Service	82,746,255	10,962,926	10,624,351	28,909,148	32,249,830
Total Distribution	73,125,281	5,976,803	9,325,344	27,516,949	30,306,184
- Transmission - In Service Area	2,749,867	175,431	321,575	975,160	1,277,701
- Stations	10,499,876	669,850	1,227,878	3,723,474	4,878,673
- Wires & Related Equipment	43,494,559	2,811,377	5,080,419	15,362,096	20,240,667
- Transformers	14,449,300	1,088,092	2,239,288	7,260,836	3,861,084
- Meters, (except Meter Reading)	1,931,679	1,232,053	456,183	195,383	48,060
- Streetlights/Floodlights	0	0	0	0	0
Customer Costs	6,569,208	4,774,619	936,407	264,002	594,179
Low-Income Assistance	3,051,766	211,503	362,599	1,128,197	1,349,467
Total	220,189,240	18,656,010	26,526,660	79,835,434	95,171,137
Share of Total	100.000%	8.473%	12.047%	36.258%	43.222%
Franchise Engy Adjustment	0	0	0	0	0
Franchise Non-Engy Adjustment	0	0	0	0	0
Seattle Res Adjust for Franch. Adjust.	0	0	0	0	0
Sum of Franchise Adjustments	0	0	0	0	0
Revised Total	220,189,240	18,656,010	26,526,660	79,835,434	95,171,137
Net Wholesale Revenue Credit	-38,638,825	-4,118,967	-5,856,688	-17,626,466	-21,012,359
Final Revenue Requirement	**136,367,747**	**0**	**0**	**62,208,968**	**74,158,778**
Load	2,745,099	152,813	314,491	1,019,728	1,258,067
New Average Annual Rate, $/MWH	**49.677**	**0.000**	**0.000**	**61.005**	**58.947**
Current Rate, $/MWH	62.210	66.380	58.600	65.392	60.026
Percent Change in Rate	**-20.15%**	**-100.00%**	**-100.00%**	**-6.71%**	**-1.80%**

$/MWH					
Energy	50.068	50.343	50.565	49.941	50.014
Production	8.018	8.062	8.098	7.998	8.009
Purchased Power	34.631	34.821	34.974	34.542	34.593
Transmission - Long Distance	1.857	1.868	1.876	1.853	1.855
Conservation	5.562	5.593	5.618	5.548	5.556
Retail Service	30.143	71.741	33.783	28.350	25.634
Total Distribution	26.638	39.112	29.652	26.985	24.089
- Transmission - In Service Area	1.002	1.148	1.023	0.956	1.016
- Stations	3.825	4.383	3.904	3.651	3.878
- Wires & Related Equipment	15.844	18.398	16.154	15.065	16.089
- Transformers	5.264	7.120	7.120	7.120	3.069
- Meters, (except Meter Reading)	0.704	8.062	1.451	0.192	0.038
- Streetlights/Floodlights	0.000	0.000	0.000	0.000	0.000
Customer Costs	2.393	31.245	2.978	0.259	0.472
Low-Income Assistance	1.112	1.384	1.153	1.106	1.073
Total	80.212	122.084	84.348	78.291	75.649
Share of Total	0.000	0.000	0.000	0.000	0.000
Franchise Engy Adjustment	0.000	0.000	0.000	0.000	0.000
Franchise Non-Engy Adjustment	0.000	0.000	0.000	0.000	0.000
Seattle Res Adjust for Franch. Adjust.	0.000	0.000	0.000	0.000	0.000
Sum of Franchise Adjustments	0.000	0.000	0.000	0.000	0.000
Revised Total	80.212	122.084	84.348	78.291	75.649
Net Wholesale Revenue Credit	-14.076	-26.954	-18.623	-17.285	-16.702
Final Revenue Requirement	**49.677**	**0.000**	**0.000**	**61.005**	**58.947**

	Network (Excluding Residential and Small)				
Total $	**Total**	**Residential**	**Small**	**Medium**	**Large**
Final Revenue Requirement	**136,367,747**			**62,208,968**	**74,158,778**
Load	2,277,795			1,019,728	1,258,067
New Average Annual Rate, $/MWH	**59.868**			**61.005**	**58.947**
Current Rate, $/MWH	62.210			65.392	60.026
Percent Change in Rate	**-3.76%**			**-6.71%**	**-1.80%**

Table 10.12
Condensed Summary of Final Allocation of Revenue Requirements for 2007-08

	Total Service Territory						
	Total	Residential	Small	Medium	Large	High Demand	Lights
Cost Share Rev.Reqmnts	1,438,506,386	554,295,181	177,964,295	323,641,681	212,287,545	139,285,514	31,032,169
Share of Cost Shr Rev Req	100.000%	38.533%	12.371%	22.498%	14.757%	9.683%	2.157%
Wholesale Net Revenue	-317,600,622	-122,380,058	-39,291,846	-71,455,226	-46,869,904	-30,752,151	-6,851,437
Other Adjustments	0	-7,177,943	1,497,202	2,507,697	1,280,423	1,892,621	0
Tot Revenue Requirement	**1,120,905,764**	**424,737,181**	**140,169,651**	**254,694,152**	**166,698,064**	**110,425,984**	**24,180,732**
Load, MWH	**19,173,605**	**6,411,733**	**2,431,239**	**4,750,645**	**3,068,805**	**2,321,353**	**189,830**
Average Rate	**58.461**	**66.244**	**57.654**	**53.613**	**54.320**	**47.570**	**127.381**
Rate without Change	61.389	67.235	58.808	60.675	57.472	53.533	75.264
Pct Chg in Rate	**-4.77%**	**-1.47%**	**-1.96%**	**-11.64%**	**-5.48%**	**-11.14%**	**69.25%**

	Total Nonnetwork (Includes Network Residential & Small)						
	Total	Residential	Small	Medium	Large	High Demand	Lights
Cost Share Rev.Reqmnts	1,263,499,815	554,295,181	177,964,295	243,806,247	117,116,408	139,285,514	31,032,169
Share of Cost Shr Rev Req	87.834%	38.533%	12.371%	16.949%	8.142%	9.683%	2.157%
Wholesale Net Revenue	-278,961,797	-122,380,058	-39,291,846	-53,828,761	-25,857,545	-30,752,151	-6,851,437
Other Adjustments	0	-7,177,943	1,497,202	2,507,697	1,280,423	1,892,621	0
Tot Revenue Requirement	**984,538,017**	**424,737,181**	**140,169,651**	**192,485,184**	**92,539,286**	**110,425,984**	**24,180,732**
Load, MWH	**16,895,810**	**6,411,733**	**2,431,239**	**3,730,917**	**1,810,738**	**2,321,353**	**189,830**
Average Rate	**58.271**	**66.244**	**57.654**	**51.592**	**51.106**	**47.570**	**127.381**
Rate without Change	61.252	67.235	58.808	59.386	55.698	53.533	75.264
Pct Chg in Rate	**-4.87%**	**-1.47%**	**-1.96%**	**-13.12%**	**-8.24%**	**-11.14%**	**69.25%**

	Network (Excludes Residential and Small)				
	Total	Residential	Small	Medium	Large
Cost Share Rev.Reqmnts	175,006,571			79,835,434	95,171,137
Share of Cost Shr Rev Req	12.166%			5.550%	6.616%
Wholesale Net Revenue	-38,638,825			-17,626,466	-21,012,359
Other Adjustments	0			0	0
Tot Revenue Requirement	**136,367,747**			**62,208,968**	**74,158,778**
Load, MWH	**2,277,795**			**1,019,728**	**1,258,067**
Average Rate	**59.868**			**61.005**	**58.947**
Rate without Change	62.210			65.392	60.026
Pct Chg in Rate	**-3.76%**			**-6.71%**	**-1.80%**

	Seattle Nonnetwork (Includes Network Res & Small)						
	Total	Residential	Small	Medium	Large	High Demand	Lights
Cost Share Rev.Reqmnts	1,035,375,403	431,612,046	152,939,198	205,681,512	99,581,913	114,528,563	31,032,169
Share of Cost Shr Rev Req	71.976%	30.004%	10.632%	14.298%	6.923%	7.962%	2.157%
Wholesale Net Revenue	-228,595,351	-95,293,463	-33,766,680	-45,411,391	-21,986,192	-25,286,188	-6,851,437
Other Adjustments	-13,224,546	-13,224,546	0	0	0	0	0
Tot Revenue Requirement	**793,555,506**	**323,094,038**	**119,172,518**	**160,270,121**	**77,595,721**	**89,242,375**	**24,180,732**
Load, MWH	**13,845,351**	**4,978,186**	**2,081,446**	**3,147,502**	**1,539,637**	**1,908,750**	**189,830**
Average Rate	**57.316**	**64.902**	**57.255**	**50.920**	**50.399**	**46.754**	**127.381**
Rate without Change	60.578	66.380	58.600	59.094	55.381	52.784	75.264
Pct Chg in Rate	**-5.39%**	**-2.23%**	**-2.30%**	**-13.83%**	**-9.00%**	**-11.42%**	**69.25%**

	Tukwila					
	Total	Residential	Small	Medium	Large	High Demand
Cost Share Rev.Reqmnts	65,825,469	9,973,765	4,576,079	11,999,573	14,519,103	24,756,950
Share of Cost Shr Rev Req	4.576%	0.693%	0.318%	0.834%	1.009%	1.721%
Wholesale Net Revenue	-14,533,276	-2,202,058	-1,010,330	-2,649,326	-3,205,600	-5,465,963
Other Adjustments	4,947,123	716,346	339,341	904,111	1,094,705	1,892,621
Tot Revenue Requirement	**56,239,317**	**8,488,053**	**3,905,090**	**10,254,358**	**12,408,207**	**21,183,608**
Load, MWH	**1,001,216**	**116,543**	**63,963**	**183,627**	**224,480**	**412,603**
Average Rate	**56.171**	**72.832**	**61.052**	**55.843**	**55.275**	**51.341**
Rate without Change	60.021	70.818	61.600	62.175	57.757	56.999
Pct Chg in Rate	**-6.41%**	**2.84%**	**-0.89%**	**-10.18%**	**-4.30%**	**-9.93%**

	Other Suburbs				
	Total	Residential	Small	Medium	Large
Cost Share Rev.Reqmnts	162,298,943	112,709,370	20,449,019	26,125,162	3,015,392
Share of Cost Shr Rev Req	11.282%	7.835%	1.422%	1.816%	0.210%
Wholesale Net Revenue	-35,833,171	-24,884,537	-4,514,836	-5,768,044	-665,753
Other Adjustments	8,277,423	5,330,257	1,157,860	1,603,587	185,718
Tot Revenue Requirement	**134,743,194**	**93,155,090**	**17,092,043**	**21,960,705**	**2,535,357**
Load, MWH	**2,049,243**	**1,317,004**	**285,830**	**399,788**	**46,621**
Average Rate	**65.753**	**70.733**	**59.798**	**54.931**	**54.382**
Rate without Change	66.476	70.150	59.700	60.410	56.247
Pct Chg in Rate	**-1.09%**	**0.83%**	**0.16%**	**-9.07%**	**-3.32%**